BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM 1829, UM 1830, UM 1831, UM 1832, UM 1833

)
)
)
)
)
)
)
)
)
)
)
)

OPENING TESTIMONY OF

STEVE IRVIN

ON BEHALF OF THE
BLUE MARMOT V, VI, VII, VIII, AND IX

October 13, 2017

I. <u>INTRODUCTION</u>

1

- 2 Q. Mr. Irvin, please state your name and business address.
- 3 A. My name is Steve Irvin. I am employed as an Executive Vice President with EDP
- 4 Renewables North America ("EDPR NA"). My business address is 808 Travis
- 5 Street Suite 700, Houston, Texas 77002.
- 6 Q. Please describe your background and experience.
- 7 A. I oversee all development efforts for EDPR NA's Central Region, West Region
- 8 and Mexico. Previously, I was Chief Commercial Officer responsible for both
- 9 Power Marketing and Origination for EDPR NA. During my 12 years with EDPR
- 10 NA, I led the successful negotiation of more than 4,000 megawatts ("MW") of
- long term renewable energy purchase agreements and the successful development
- of over 1,400 MWs of projects now in operation. Prior to joining EDPR NA in
- 13 2005, I served as Vice President at Enron North America, where I worked on
- settling commodity trading contracts and on the greenfield development,
- 15 construction and financing of energy assets in Mexico. I received a Bachelor of
- Science in Mathematics from Vanderbilt University in 1990 and a Master of
- 17 Business Administration from Thunderbird The Garvin School of International
- Management in 1997.
- 19 Q. On whose behalf are you appearing in this proceeding?
- 20 A. Blue Marmot V, Blue Marmot VI, Blue Marmot VII, Blue Marmot VIII, Blue
- 21 Marmot IX (jointly, "Blue Marmots") and their parent company, EDPR NA.
- 22 **O.** How is your testimony organized?
- 23 A. My testimony will first provide an overall summary of our case. Then I will
- 24 describe the basic facts of the Blue Marmots, including their eligibility for

1 standard renewable off-system variable power purchase agreements ("PPAs") 2 under Portland General Electric Company's ("PGE's") published Schedule 201 3 rates, and their transmission arrangements for delivering power to PGE. My 4 testimony will next cover how EDPR NA relied upon certain Oregon Public 5 Utility Commission (the "Commission" or "OPUC") policies in deciding to 6 pursue business in Oregon and how the Blue Marmots are experiencing harm as a 7 result of PGE's actions, which have been inconsistent with our interpretation of 8 the policies of both the OPUC, as well as the Federal Energy Regulatory 9 Commission ("FERC"). Finally, I will summarize the testimonies of the Blue 10 Marmot witnesses that will follow me. 11 Can you please provide an overall summary of the case? Q. 12 A. The essential question in this case is whether PGE can impose additional 13 transmission costs on the Blue Marmots after they have arranged for delivery of 14 their net output to PGE's system. PGE has taken the position that, even though 15 the Blue Marmots have made complete transmission arrangements to wheel their

net output to a point of delivery ("POD") on PGE's system, the Blue Marmots

or 2) pay for transmission to deliver to another POD, which from a practical

transmission service beyond the transmission service the Blue Marmots have

perspective means paying for a second separate and additional path of

must either: 1) pay for studies and upgrades on PGE's own transmission system;

16

17

18

19

20

21

already secured.

II. BLUE MARMOT PROJECTS

1

21

22

2 Q. Please provide a high-level description of the Blue Marmot projects.¹

3 A. Each Blue Marmot Project will be a 10 MW alternating current ("ac") nameplate 4 solar photovoltaic generation facility located in Lake County, Oregon. Each Blue Marmot Project qualifies as a small power production facility, eligible to receive 5 6 standard PPA pricing under PGE's Schedule 201. This is because each Blue 7 Marmot Project's nameplate capacity of electrical generating facilities using the 8 same motive force will not exceed 10 MW ac, and, while each Blue Marmot 9 Project is owned by EDPR NA, none are within 5 miles of another. Each Blue 10 Marmot Project has completed the FERC process to self-certify as a qualifying 11 facility ("QF") under the Public Utility Regulatory Policies Act ("PURPA"). 12 Each Blue Marmot Project will interconnect with PacifiCorp, and has made 13 arrangements for the transmission of power to PGE's system in the form of 14 executed transmission service agreements with PacifiCorp to wheel each Blue 15 Marmot Project's entire net output to PGE's system. 16 Q. Are there any other eligibility requirements in PGE's Schedule 201 for a 17 project to qualify for a standard renewable off-system variable PPA? 18 Α. Yes. The Seller under Schedule 201 must establish creditworthiness with a 19 written acknowledgement that it is current on all existing debt obligations and that 20 it was not a debtor in a bankruptcy proceeding within the preceding 24 months.

Other than the issue of whether the Blue Marmots have obtained the necessary transmission arrangements, it is my understanding that PGE does not dispute any of the facts in Section II of my testimony.

The Blue Marmots meet this requirement. A OF located outside PGE's service

territory is also responsible for "the transmission of power at its cost to the

1		Company's service territory", which the Blue Marmots have provided for via
2		PacifiCorp transmission service to PGE's system.
3	III.	OREGON MARKET
4 5	Q.	How have you relied on OPUC policies in deciding to pursue development of the Blue Marmot Projects?
6	A.	We relied on the OPUC to provide a predictable market opportunity for
7		development of renewable energy generation through its PURPA implementation
8		and policies, including but not limited to PGE's Schedule 201. Renewable energy
9		developers like EDPR NA generally need a state to establish a settled and uniform
10		institutional climate for PURPA development before they will invest significant
11		resources in that state. It is important to developers that the Commission act in a
12		stable and consistent manner, including providing accurate price signals, clear
13		contract terms, and full information regarding PPAs and the requirements to enter
14		into PPAs.
15 16	Q.	Does this mean that EDPR NA assumed that there would be no changes to Oregon PURPA policies or Schedule 201?
17	A.	No. We understood aspects of Schedule 201 to be subject to change as markets
18		evolve, e.g. avoided costs being updated at specified points during the year.
19		However, EDPR NA viewed Schedule 201 as offering a rules-based and
20		standardized route to contracting. Specifically, we understood that projects
21		qualifying for standard PPAs under Schedule 201 are entitled to avoided costs in
22		effect at the time projects establish legally enforceable obligations, under the

terms in the OPUC-approved form standard PPA used by PGE.

23

- Q. Did EDPR NA rely upon the fact that Schedule 201 only required the Blue Marmots to deliver their net output to a POD on PGE's system, without being required to pay for transmission upgrades on PGE's system?
- 4 **A.** Yes. EDPR NA was aware that previous QFs had executed PPAs with PGE, and that PGE had agreed to these QFs delivering at the PACW.PGE POD. EDPR NA pursued development of the Blue Marmot projects relying upon the terms of Schedule 201 and the standard renewable off-system variable PPA being honored by PGE and enforced by the OPUC, including a QF only needing to deliver its net output to a POD on PGE's system of the QF's choosing.

10 IV. HARM TO BLUE MARMOT

11 Q. What economic harm would result from the projects not moving forward?

12 A. The Blue Marmots have anticipated investing at least \$50 million in total in 13 bringing these projects to commercial operations. Given that they have been 14 developed specifically to satisfy the requirements for selling to PGE under 15 Schedule 201, it is unlikely they all could successfully pursue other commercial 16 opportunities. To date the Blue Marmot Projects have invested significant 17 resources in advancing project development, under the assumption that the 18 projects had a predictable path to executing PPAs with PGE. This includes 19 signing agreements with landowners to purchase or lease land for the projects, 20 working through the interconnection process with PacifiCorp, conducting 21 environmental studies to support project permitting and meet EDPR NA's internal 22 environmental standards, and signing transmission service agreements with 23 PacifiCorp to wheel the output of the projects to PGE's system. These costs 24 would be unrecoverable if the projects do not move forward.

\sim	XX71 4	• 1		• •	41	4 1 1 6
().	what econ	omic hari	n is ari	sing fror	n the cu	rrent delay?

1

11

12

13

2 A. Apart from the costs described above that would result from the projects not 3 moving forward, even if they do move forward, the delay in PPA execution is 4 creating problematic uncertainty. For example, the Blue Marmot Projects have 5 delayed conducting several studies required for undertaking detailed engineering 6 analyses and securing required permits, due to their high costs, until the PPA 7 uncertainty has been resolved. This pushes back the timeline on which the 8 projects can be brought to commercial operations. The longer it takes to realize 9 the return from investments already made to date, the more challenging the 10 economics of the projects become.

Q. What harm would the Blue Marmot Projects experience under PGE's offered options of paying for upgrades at PACW.PGE or delivering at another POD?

14 The only practicable alternative POD would be the BPAT.PGE POD. Since the Α. 15 Blue Marmot Projects will interconnect with PacifiCorp, delivering at BPAT.PGE 16 would require paying for two "wheels" or segments of transmission service: one 17 from PacifiCorp to Bonneville Power Administration's ("BPA's") system at the PAC.BPAT POD and one from BPA to PGE's system at the BPAT.PGE POD. 18 19 Over the term of the PPA, this second wheel would add at least \$14 million in 20 total additional costs across the Blue Marmot Projects, assuming no significant 21 increases in BPA's transmission rates. Regarding paying for upgrades at the 22 PACW.PGE interface, at this point in time there is no firm basis for estimating 23 what those costs might be.

V. WITNESS SUMMARY

- 2 Q. Can you please summarize the witnesses and testimony that will follow you?
- 3 A. Yes, the Blue Marmots are sponsoring testimony by William Talbott and Keegan
- 4 Moyer.

1

15

16

17

18

19

20

21

- 5 Q. Please summarize Mr. Talbott's testimony.
- 6 A. Mr. Talbott is the primary EDPR NA employee who negotiated with PGE 7 regarding the Blue Marmot Projects. Mr. Talbott will summarize the PPA 8 negotiations, the transmission arrangements required under the PPAs and 9 Schedule 201, and how the Blue Marmots have satisfied those transmission 10 obligations by purchasing firm point-to-point transmission on PacifiCorp's system 11 to deliver the Blue Marmots' net output to PGE at the PACW.PGE POD. Mr. 12 Talbott will also explain the general requirements to form a legally enforceable 13 obligation, and why each of the Blue Marmot Projects has established a legally 14 enforceable obligation by executing either a final executable PPA provided by

Of critical importance, PGE agreed to purchase the net output of the Blue Marmots projects at the PACW.PGE POD by providing executable PPAs and stating that it would purchase the entire net output of the Blue Marmot Projects, if those PPAs were executed. Regardless of what PGE's current views are regarding the need to acquire additional transmission, PGE should live up to its promises. PGE is not acting as a good faith business partner.

- 22 Q. Please summarize Mr. Moyer's testimony.
- A. Mr. Moyer is a regulatory consultant who is an expert on state and federal regulatory matters, including PURPA and transmission issues. Mr. Moyer

PGE or executing the final draft PPA provided by PGE.

provides an explanation of the Blue Marmots' obligations under PURPA, which are to arrange for delivery to a POD on PGE's system of the QF's choosing. PGE is then required to take responsibility for the power, which includes deciding what PGE wants to use the power for and how PGE will transmit that power to its preferred location on its system. Mr. Moyer will also explain that there are limited exceptions to PGE's mandatory purchase obligation, none of which apply to the Blue Marmots.

While it is not the responsibility of the Blue Marmots to manage PGE's generation and transmission assets, Mr. Moyer will identify some options that PGE could have taken and could still take to fulfill its responsibility to accept and manage the Blue Marmots' net output, which include paying for studies and upgrades at the PACW.PGE POD, backing down its own generation or transmission, altering the terms of its participation in the Western Energy Imbalance Market, and/or requesting that FERC accepts changes to its transmission tariffs and/or protocols that would allow PGE to accept QF deliveries that would exceed posted available transfer capability at the PACW.PGE POD by making changes to system operations. There are numerous options that PGE can employ, and PGE has refused to consider any of them, and is instead simply refusing to live up to its obligations to purchase the Blue Marmots' net output.

Mr. Moyer will also explain how PGE is seeking to alter the avoided cost price paid to the Blue Marmots by requiring them to pay for additional transmission costs.

Finally, Mr. Moyer will testify that PGE is unduly discriminating against the Blue Marmots because PGE: 1) has entered into PPAs with other QFs that are planning to deliver to the PACW.PGE POD, and PGE is treating those QFs differently from the Blue Marmots; and 2) has claimed new transfer capability that became available after PGE refused to execute PPAs with the Blue Marmots for PGE's own use.

VI. REMEDY

1

2

3

4

5

6

7

- 8 Q. What are the Blue Marmots asking the OPUC to do?
- 9 A. The Blue Marmots' two primary requests are that: 1) PGE be required to accept 10 the entire net output of the Projects at the PACW.PGE POD without requiring the 11 Blue Marmots to pay for studies and upgrades at the PACW.PGE POD or to 12 deliver their net output to a different POD; and 2) PGE be required to pay the 13 avoided cost rates included in the Schedule 201 attached to each of the partially 14 executed PPAs. This includes barring PGE from seeking to impose any costs on 15 the Blue Marmots regarding congestion, curtailing their net output, or otherwise 16 raising any concerns regarding deliverability, wheeling or transmission. The Blue 17 Marmots are also asking that penalties be imposed upon PGE and that the OPUC 18 affirmatively find that PGE has violated the relevant PURPA-related laws, rules 19 and orders.

At bottom, PGE should be required to execute the partially executed PPAs and simply accept the power once it is delivered at the PACW.PGE POD.

22 VII. <u>CONCLUSION</u>

- 23 Q. Does this conclude your testimony?
- 24 **A.** Yes.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM 1829, UM 1830, UM 1831, UM 1832, UM 1833

BLUE MARMOT V LLC (UM 1829))
BLUE MARMOT VI LLC (UM 1830))
BLUE MARMOT VII LLC (UM 1831))
BLUE MARMOT VIII LLC (UM 1832))
BLUE MARMOT IX LLC (UM 1833))
Complainants)
VS.)
PORTLAND GENERAL ELECTRIC)
COMPANY)
Defendant)
Pursuant to ORS 756.500.)
)

OPENING TESTIMONY OF

WILLIAM TALBOTT

ON BEHALF OF THE
BLUE MARMOT V, VI, VII, VIII, AND IX

October 13, 2017

		19200
1	I.	INTRODUCTION
2	Q.	Mr. Talbott, please state your name and business address.
3	Α.	My name is William Talbott. I am employed as a Development Project Manager
4		with EDP Renewables North America ("EDPR NA"). My business address is 53
5		SW Yamhill Street, Portland, Oregon 97204.
6	Q.	Please describe your background and experience.
7	A.	I lead development of solar projects for EDPR NA in the West Region, which
8		includes market analysis and prioritization based on commercial prospects, site
9		identification, site acquisition, interconnection, permitting, power marketing and
10		power purchase agreement ("PPA") negotiations. I have served in this role since
11		2015. Prior to joining EDPR NA, I worked as a management consultant with
12		McKinsey & Company. I received a Bachelor of Arts in Economics from
13		Pomona College, a Master of Business Administration from the MIT Sloan
14		School of Management and a Master of Public Administration from the Harvard
15		Kennedy School.
16	Q.	On whose behalf are you appearing in this proceeding?
17	A.	Blue Marmot V, Blue Marmot VI, Blue Marmot VII, Blue Marmot VIII, Blue
18		Marmot IX (jointly, "Blue Marmots") and their parent company, EDPR NA. The
19		Blue Marmots own each of the individual projects (jointly, "Blue Marmot
20		Projects").
21	Q.	How is your testimony organized?
22	A.	First, I will describe the series of exchanges through which the Blue Marmots
23		pursued and ultimately signed standard renewable off-system variable PPAs with

Portland General Electric Company ("PGE"). Second, I will summarize the

24

1 position PGE has taken in justifying not countersigning the partially executed 2 Blue Marmot PPAs on the grounds of transmission constraints. Third, I will 3 explain the transmission arrangements required by Schedule 201 and the PPA and 4 how the Blue Marmots have satisfied those requirements. Fourth, I will 5 summarize the concept of a legally enforceable obligation, including the Federal 6 Energy Regulatory Commission ("FERC") precedent on the factors that establish 7 a legally enforceable obligation, as well as the Oregon Public Utility Commission 8 ("OPUC") policy regarding legally enforceable obligations. Finally, I will 9 explain how, contrary to PGE's position, the Blue Marmots have demonstrated 10 the ability to meet the requirements under Schedule 201 and the PPA for 11 delivering power to PGE. 12 II. POWER PURCHASE AGREEMENT NEGOTIATIONS 13 Q. When did development of the Blue Marmot Projects begin? 14 A. Work began in the first quarter of 2016. This entailed desktop mapping of the 15 Lakeview area of Lake County to identify development constraints, reaching out 16 to owners of potentially suitable sites to gauge their interest in leasing or selling 17 land for purposes of solar development, and traveling to the Lakeview area to 18 meet with interested landowners. Initial work also included reviewing PGE's 19 Schedule 201 for terms and eligibility rules. In February 2016, we requested the 20 list of materials and information required to request a PPA from PGE under 21 Schedule 201. 22 Did each Blue Marmot project pursue a PPA on the same timeline? Q. 23 Α. No. Since the projects did not all secure site control on the same timeline, they

did not all pursue PPAs on the same timeline. Blue Marmot V and VI were the

24

first projects to begin the process and moved on the same timeline. Blue Marmot

VII and IX were the next to begin the process and moved on the same timeline,

and Blue Marmot VIII was the last and moved on its own timeline.

Q. Can you please summarize the series of events that led to Blue Marmot V and VI executing PPAs provided by PGE?

A.

On August 1, 2016, Blue Marmot V and VI provided information and materials required for requesting PPAs with PGE. Over the course of the next few months, Blue Marmot V and VI and PGE exchanged information and communicated regarding issues related to the sale of the net output of the Blue Marmot V and VI Projects to PGE, including but not limited to contract terms, required information, and project details. On December 20, 2016, Blue Marmot V and VI requested final draft PPAs for the Blue Marmot V and VI Projects.

On January 12 and January 16, 2017, PGE provided Blue Marmot V and VI with executable PPAs for the Blue Marmot V and VI Projects, as well as accompanying cover letters. The letters stated that PGE had determined that Blue Marmot V and VI had provided sufficient information to allow PGE to prepare executable PPAs, and that PGE had attached executable PPAs for the Blue Marmot V and VI Projects. Each letter further stated that, if Seller "executes the enclosed agreement without alteration and returns the partially executed agreement to PGE for full execution, Seller will have established a legally enforceable obligation." Finally, the letters stated that Blue Marmot V and VI

Blue Marmot/201, Talbott/1-121 (PGE emails and Blue Marmot V and VI executable PPAs)(On January 12, 2017, PGE initially provided the incorrect draft of the Blue Marmot V PPA, but then provided the correct executable PPA on January 16, 2017.).

were entitled to receive PGE's renewable avoided cost rates in effect at the time of execution, if Blue Marmot V and VI executed the final executable PPAs without alteration.

Α.

On March 29, 2017, Blue Marmot V and VI executed the final executable PPAs without alteration.² The executed PPAs were delivered by hand to PGE on March 31, 2017.

Q. Can you please provide the same summary for Blue Marmot VII and IX?

On December 21, 2016, Blue Marmot VII and IX provided information and materials required for requesting PPAs with PGE. Over the course of the next couple months, Blue Marmot VII and IX and PGE exchanged information and communicated regarding issues related to the sale of the net output of the Blue Marmot VII and IX Projects to PGE. On February 28, 2017, Blue Marmot VII and IX requested final executable PPAs for the Blue Marmot VII and IX Projects.

On March 21, 2017, PGE provided Blue Marmot VII and IX with cover letters and executable PPAs for the Blue Marmot VII and IX Projects.³ The letters stated that PGE had determined that Blue Marmot VII and IX had provided sufficient information to allow PGE to prepare executable PPAs, and that PGE had attached executable PPAs for the Blue Marmot VII and IX Projects. Each letter further stated that, if Seller "executes the enclosed agreement without alteration and returns the partially executed agreement to PGE for full execution, Seller will have established a legally enforceable obligation." Finally, the letters

Blue Marmot/202, Talbott/1-131 (Blue Marmot V and VI executed PPAs).

Blue Marmot/201, Talbott/122-220 (PGE emails and Blue Marmot VII and IX executable PPAs)(PGE's letter incorrectly identified the Blue Marmot IX Project as Blue Marmot XI).

	stated that Blue Marmot VII and IX were entitled to receive PGE's renewable
	avoided cost rates in effect at the time of execution, if Blue Marmot VII and IX
	executed the final executable PPAs without alteration.
	On March 29, 2017, Blue Marmot VII and IX executed the final
	executable PPAs without alteration. ⁴ The executed PPAs were delivered by hand
	to PGE on March 31, 2017.
Q.	Did the letters sent by PGE along with the executable PPAs for Blue Marmot V, VI, VII and IX state any contingencies or conditions upon which the provisions of the letter were based?
A.	No, these were unconditional statements. Each letter stated: "If Seller executes
	the enclosed agreement without alteration and returns the partially executed
	agreement to PGE for full execution, Seller will have established a legally
	enforceable obligation. Seller is entitled to receive PGE's [Standard Avoided
	Costs OR Renewable Avoided Costs] in effect at the time Seller executes the
	enclosed agreement without alteration." Therefore, PGE clearly and
	unambiguously stated that signing the executable PPAs would create a legally
	enforceable obligation at the renewable avoided costs in effect at the time of
	signing.
Q.	What happened after Blue Marmot V, VI, VII and IX sent PGE executed PPAs?
A.	On April 5, 2017, Blue Marmot asked PGE when PGE would execute the four
	final executable PPAs signed by Blue Marmot V, VI, VII and IX. On April 5,
	2017, PGE informed Blue Marmot that PGE usually takes a couple of weeks from
	A. Q.

Blue Marmot/202, Talbott/132-197, 264-329 (Blue Marmot VII and IX executed PPAs).

the date the QF executes the executable PPA for PGE to execute the partially executed PPA.

On April 6, 2017, PGE informed Blue Marmot that there were two changes PGE wished to make to the PPAs that PGE had provided to Blue Marmot V, VI, VII and IX as executable and that Blue Marmot V, VI, VII and IX had executed. These two non-substantive and immaterial changes were to: 1) attach the FERC Form 556 qualifying facility ("QF") self-certification forms that Blue Marmot V, VI, VII and IX had previously provided to PGE; and 2) adding page numbers. It is my understanding that PGE has executed previous PPAs with QFs without including the FERC Form 556, and that these non-substantive and immaterial changes did not change the Blue Marmot V, VI, VII and IX Projects' legally enforceable obligations. On April 7, 2017, PGE provided corrections to the partially executed PPAs to add the FERC form 556 and to correct the page numbers. On April 10, 2017, Blue Marmot approved the corrections to the

Q. What about the timeline for Blue Marmot VIII?

A. On February 2, 2017, Blue Marmot VIII provided information and materials required for requesting a PPA with PGE. Over the next several weeks, Blue Marmot VIII and PGE exchanged information and communicated regarding issues related to the sale of the net output of the Blue Marmot VIII Project to PGE. On March 22, 2017, PGE provided a final draft PPA for the Blue Marmot VIII Project.⁵ On March 24, 2017, Blue Marmot VIII requested an executable

Blue Marmot/201, Talbott/221-270 (PGE emails and Blue Marmot VIII draft PPA).

4	0.	What interaction did you have with PGE on April 17, 2017?
3		clarifying information by April 17, 2017.
2		Marmot VIII that it would provide an executable PPA, or request additional or
1		PPA for the Blue Marmot VIII Project. On March 28, 2017, PGE informed Blue

Α.

A.

On April 17, 2017, PGE inquired about the point of delivery ("POD") for the Blue Marmot Projects. On April 18, 2017, PGE was informed that the anticipated POD for the Blue Marmot Projects was PACW.PGE.⁶ On April 19, 2017, PGE stated that the POD was constrained and that it was concerned that deliveries to the POD might not be feasible. On April 19, 2017, PGE stated that if PGE's evaluation of the alleged congestion at the POD went past May 1, 2017, then PGE would honor the avoided cost prices currently in effect for both the partially executed PPAs for Blue Marmot V, VI, VII and IX, as well as for Blue Marmot VIII.

13 Q. Did the Blue Marmot Projects continue to attempt to obtain fully executed PPAs?

Yes. On April 19, 2017, Blue Marmot expressed its concern with PGE's refusal to execute the partially executed PPAs for Blue Marmot V, VI, VII and IX, and to provide an executable PPA for Blue Marmot VIII. On April 19, 2017, PGE refused to execute the partially executed PPAs. On April 20, 2017, Blue Marmot specifically informed PGE that its expectation was that PGE countersign without delay the partially executed PPAs, and that Blue Marmot V, VI, VII and IX were continuing to commit and obligate themselves to sell power to PGE from the Blue Marmot V, VI, VII and IX Projects at the Schedule 201 rates, terms, and

PACW.PGE is a scheduling point between PGE's and PacifiCorp's systems, and constitutes several actual points of physical interconnections between PGE's and PacifiCorp's systems.

conditions in the partially executed PPAs. On April 24, 2017, Blue Marmot attempted to reach an agreement regarding PGE's execution of the partially executed PPAs, and was unable to reach agreement. On April 24, 2017, Blue Marmot sent PGE a demand letter requesting that PGE execute the partially executed PPAs or Blue Marmot V, VI, VII and IX would file a complaint with the OPUC on April 28, 2017. On April 27, 2017, PGE informed Blue Marmot that it would not execute the partially executed PPAs.

Q. What about Blue Marmot VIII?

1

2

3

4

5

6

7

8

9 Α. On April 20, 2017, Blue Marmot VIII communicated to PGE that it was 10 committing and obligating itself to sell power to PGE from the Blue Marmot VIII 11 Project at the Schedule 201 rates, terms, and conditions in the final draft PPA 12 provided by PGE. On April 28, 2017, Blue Marmot VIII executed the last draft 13 PPA that PGE provided to Blue Marmot VIII. Blue Marmot VIII made no 14 changes to the last draft PPA, other than executing the PPA. Blue Marmot VIII 15 did this because it was concerned that PGE would not provide an executable PPA for Blue Marmot VIII, and because Blue Marmot VIII had requested an 16 17 executable PPA exactly matching the final draft PPA and was prepared to commit itself to sell power to PGE under the terms of that PPA. ⁷ Blue Marmot VIII 18 19 unequivocally committed itself to sell the net output of the Blue Marmot VIII 20 Project at the terms and conditions included in the partially executed PPA, 21 including but not limited to being subject to penalties for failing to deliver energy 22 on the scheduled commercial on-line date.

⁷ Blue Marmot/202, Talbott/198-263 (Blue Marmot VIII executed PPA).

1	Q.	Had PGE previously inquired about or expressed concern over the viability
2		of Blue Marmot's POD?

A. Prior to April 17, 2017, PGE never specifically requested information regarding the POD for any of the Blue Marmot Projects or provided any indication regarding its concerns about potential constraints at the POD. Although PGE never specifically requested information about the POD, each Blue Marmot Project communicated in its request for an initial draft PPA that it would be interconnecting with PacifiCorp, from which it could reasonably be inferred that each Project would deliver to PGE's system at the interface point between the PacifiCorp and PGE systems, or the PACW.PGE POD.

Moreover, on November 14, 2016, Blue Marmot sent several questions to PGE seeking to clarify settlement details under the PPA for projects delivering to PGE via PacifiCorp, again implying that the projects intended to deliver to PGE's system at the PACW.PGE POD. PGE did not raise any concerns about the Blue Marmot Projects delivering to the PACW.PGE POD in response to these questions. Additionally, the Required Facility Documents in the partially executed PPAs specifically state that the Blue Marmots will secure transmission service agreements with PacifiCorp, but do not mention transmission service from the Bonneville Power Administration ("BPA"), which would be required to deliver to another POD.

With any reasonable level of attention, PGE could have determined that the Blue Marmots intended to deliver to PGE's system at the PACW.PGE POD. By providing executable PPAs, PGE committed to purchase the Blue Marmots' net output at this POD, and pay the then current Schedule 201 avoided cost rates

1		without requiring the Blue Marmots to pay for studies or upgrades on PGE's
2		transmission system or pay for transmission service to a different POD.
3 4	Q.	Please summarize your interactions with PGE since April 27 regarding this matter.
5	A.	PGE communicated on May 18, 2017 that it cannot accept delivery from Blue
6		Marmot at the PACW.PGE POD because of transmission constraints at this POD
7		arising from PGE's acquisition of transmission rights to participate in the Western
8		Energy Imbalance Market ("EIM"). Blue Marmot met with PGE on June 1, 2017
9		and again on June 19, 2017 to explore potential settlement options.
10	Q.	What has PGE's position been?
11	A.	PGE has stated that there is "insufficient long-term firm available transmission
12		capacity (ATC) at this POD" and that, "Given the lack of long-term firm ATC at
13		the PACW.PGE POD, PGE cannot agree to accept delivery of Blue Marmot's
14		output at this POD." PGE has "declined to sign the executable PPA[s] until the
15		parties agree on an alternative delivery arrangement." PGE has communicated
16		that Blue Marmot has two options: 1) either pay for upgrades at the PACW.PGE
17		POD; or 2) deliver to a different POD, i.e. the BPAT.PGE POD.
18 19	Q.	Has PGE changed its position about whether the Blue Marmot V, VI, VII and IX have formed legally enforceable obligations?
20	A.	Yes. PGE now claims that the legally enforceable obligations described in the
21		cover letters accompanying the executable PPAs for Blue Marmot V, VI, VII and
22		IX are actually contingent upon Blue Marmot making alternative delivery
23		arrangements.

III. TRANSMISSION ARRANGEMENTS

Α.

Q. What transmission arrangements have Blue Marmot already made and what new transmission arrangements would be required to deliver at BPAT.PGE?

EDPR NA has executed on the Blue Marmots' behalf transmission service agreements with PacifiCorp for long term firm point to point transmission service with rollover rights for the full capacity of the Blue Marmot Projects to deliver the net output to the PACW.PGE POD, which is the interface between the PacifiCorp and PGE systems. The total interconnection cost for the Blue Marmots is expected to be approximately \$9.5 million, of which \$5.4 million would eventually be reimbursed to Blue Marmot, and the cost of PacifiCorp transmission is expected to be approximately \$34 million over the term of the PPAs.

Delivering at BPAT.PGE would entail redirecting the PacifiCorp transmission service to the PACW.BPAT interface point, and then adding a second path of BPA transmission service from PACW.BPAT to the interface between BPA and PGE at the BPAT.PGE POD. This second leg of transmission would add over \$14 million in costs total to the Blue Marmot Projects over the term of the PPAs. The testimony of Keegan Moyer will address transmission topics in greater detail.

19 Q. What are the Seller's obligations under Schedule 201 PPAs?

A. The Sellers' obligations are to deliver power to PGE's system. Section 4.1 states

"Commencing on the Effective Date and continuing through the Term of this

Agreement, Seller shall sell to PGE the entire Net Output delivered from the

Facility at the Point of Delivery" and Section 1.27 states "Point of Delivery means

the PGE System." There is no further delineation of acceptable PODs and neither

solution offered by PGE (upgrades at the PACW.PGE POD or delivery to an alternative POD) is contemplated under the contract. PGE is now seeking to alter the PPA and require the Blue Marmots to agree to specify that it will pay for transmission costs not contemplated under the PPA.

Indeed, PGE repeatedly emphasized through multiple conversations with Blue Marmot that other than variable terms in the contract, there can be no changes to the Schedule 201 contract to clarify or stipulate unique details or arrangements for specific projects. There is no variable term for the POD and, as stated previously, PGE never inquired about PODs prior to April 17, 2017, until after providing executable PPAs.

The closest thing to a variable term for POD in the PPA is specifying the interconnecting utility. For off-system QFs such as the Blue Marmot projects interconnecting with PacifiCorp, it could be reasonably inferred that the PACW.PGE POD would be the interface point between the PacifiCorp and PGE systems.

Additionally, the Blue Marmot Projects stipulated in the list of Required Facility Documents in Exhibit B that prior to the Commercial Operation Date, the projects would secure Transmission Service Agreements with PacifiCorp. Given that there was no mention of Transmission Service Agreements with BPA, it could be reasonably inferred that each of the projects intended to deliver to the PACW.PGE POD.

In sum, the contract simply requires delivery to PGE's system, with no negotiation on a mutually agreeable POD required, and Blue Marmot's intention

1	to deliver to the PACW.PGE POD was clear from the information included in the
2	executable contracts provided by PGE.

- Q. What has PGE communicated regarding the ability of Blue Marmot to
 receive the renewable avoided costs in effect at the time Blue Marmot
 executed PPAs for the Blue Marmot Projects?
- A. PGE confirmed in its May 18, 2017 answer to complaints filed by Blue Marmot that it communicated in April 2017 that if evaluating the feasibility of Blue Marmot delivering at the PACW.PGE POD went past May 1, 2017 (when PGE filed to reduce its renewable avoided cost rates), then PGE would continue to honor the avoided cost prices in effect at the time Blue Marmot executed its PPAs.

12 IV. LEGALLY ENFORCEABLE OBLIGATIONS

13 Q. What is a legally enforceable obligation?

14 A. While I am not a lawyer, I will explain my understanding of legally enforceable 15 obligations. FERC has established an administrative rule and policy that ensures 16 that a QF has the right and obligation to sell its net output to a utility pursuant to a contract or a legally enforceable obligation.⁸ The QF enters into a legally 17 18 enforceable obligation by committing itself to sell power to an electric utility. A 19 legally enforceable obligation is broader than simply a contract between a utility 20 and a QF, and may exist without a contract. Thus, a QF can require a utility to 21 purchase its power even if the utility has refused to enter into a contract.

^{8 18} CFR 292.304(d).

1 Q. What is the purpose of a legally enforceable obligation?

A. It is intended to ensure that a utility cannot refuse to sign a contract, so that a later
and lower avoided cost becomes applicable, or cannot impose additional terms
and conditions like curtailing power deliveries. In other words, a legally
enforceable obligation allows a QF to "lock in" current avoided cost rates and
contract terms, especially when a utility is delaying or otherwise imposing
unreasonable terms and conditions.

8 Q. How is a legally enforceable obligation formed?

18

19

20

21

22

When the QF commits itself to sell its net output at specific terms and conditions.

While I am not an expert in issues related to the Public Utility Regulatory Policies

Act ("PURPA"), my understanding is that the OPUC has concluded that it is up to

the QF, and not the utility, to determine when a legally enforceable obligation has

been formed. In a recent 2016 order, the OPUC noted that "a QF has the power to

determine the date for which avoided costs are calculated by obligating itself to

provide power."9

Q. Has the OPUC provided further guidance regarding the formation of legally enforceable obligations?

A. Yes, in the same order, the OPUC explained that a legally enforceable obligation cannot be formed until the utility and QF have undertaken the contracting process, and negotiations have progressed beyond the initial communications. The OPUC then adopted a policy that a legally enforceable obligation and a QF's right to then current avoided cost rates begins at the time the QF signs a final draft of an

Re OPUC Investigation into QF Contracting and Pricing, Docket No. UM 1610, Order No. 16-174 at 23-24 (May 13, 2016)

1		executable contract that includes specific requirements, including on line dates,
2		minimum and maximum output, penalties for failure to deliver, etc. The OPUC
3		also recognized that there may be problems, delays or obstructions toward the
4		execution of a final contract that will entitle a QF to then current avoided cost
5		rates prior to the utility sending an executable PPA.
6	Q.	How do these factors apply to the Blue Marmot Projects?
7	A.	All five projects were well past the point of initial communications, and all five
8		projects unequivocally committed themselves to sell their net output at specific
9		terms and conditions. This included the terms and conditions of the executed
10		PPAs, which determined the applicable avoided cost rates and included details
11		regarding commercial operation dates, minimum and maximum net output,
12		penalties, etc. Thus, all five projects have satisfied both the OPUC's and FERC's
13		standard for forming legally enforceable obligations.
14 15	Q.	Have the Blue Marmot V, VI, VII and IX Projects exceeded the standard for forming legally enforceable obligations?
16	A.	Yes. PGE provided executable PPAs with all the required terms, conditions and
17		rates, which Blue Marmot V, VI, VII and IX all signed. I agree with PGE's
18		statements in its letters that Blue Marmot V, VI, VII and IX established a legally
19		enforceable obligation once they executed without alteration the executable PPAs
20		and then returned the partially executed PPAs to PGE for full execution.
21 22	Q.	Has PGE agreed that the Blue Marmots have formed legally enforceable obligations?
23	A.	No. PGE takes the position that the Blue Marmots will only have formed legally
24		enforceable obligations if they agree to pay for transmission upgrades at the

PACW.PGE POD, or deliver to a different POD. This is directly inconsistent with PGE's prior statements made when it provided the executable PPAs.

In addition, PGE appears to be taking the position that the Blue Marmots will not have formed legally enforceable obligations or otherwise be eligible for the avoided cost rates at the time they executed the PPAs, even if the OPUC, FERC or a court agrees with the Blue Marmots that the Blue Marmots have satisfied their obligations under PURPA and the partially executed contracts by arranging delivery at the PACW.PGE POD. Regardless of the outcome of this litigation, or whether PGE can impose additional transmission costs on a QF that delivers its net output to a POD on its system, the Blue Marmots should be eligible for the prices at the time they executed their PPAs. The Blue Marmots have committed to sell their net output under the terms and conditions of the partially executed PPAs regardless of transmission arrangements the OPUC, FERC, or a court ultimately decide are necessary.

V. <u>CONCLUSION</u>

- **Q.** Does this conclude your testimony?
- **A.** Yes.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM 1829, UM 1830, UM 1831, UM 1832, UM 1833

BLUE MARMOT V LLC (UM 1829)	
BLUE MARMOT VI LLC (UM 1830)	
BLUE MARMOT VII LLC (UM 1831)	
BLUE MARMOT VIII LLC (UM 1832)	
BLUE MARMOT IX LLC (UM 1833)	
Complainants	
VS.	
PORTLAND GENERAL ELECTRIC	
COMPANY	
Defendant	
Pursuant to ORS 756.500.	

EXHIBIT BLUE MARMOT/201 PGE EMAILS, EXECUTABLE AND FINAL PPAS

October 13, 2017

From: Shawn Davis <Shawn.Davis@pgn.com>
Sent: Thursday, January 12, 2017 4:37 PM

To: Talbott, Will

Subject: RE: Blue Marmot V and Blue Marmot VI

Attachments: PGE EDPR Blue Marmot V Executable Letter.pdf; Revised Draft Standard Off System Marmot VI

Letter.pdf; Blue Marmot VI Standard Renewable Off System Executable Contract .pdf; Draft Standard

Off System Blue Marmot V Standard Renweable.pdf

Will,

Please find attached four documents. A letter and executable contract for Blue Marmot V and Blue Marmot VI. If you have any questions or concerns please do not hesitate to call.

Kindest regards,

Shawn P Davis |

Portland General Electric | 121 SW Salmon St. 3WTC0306 | Portland, Oregon 97204|

W: 503-464-7013 | F: 503-464-7608 |

E: shawn.davis@pgn.com



January 12, 2017

Will Talbott EDP Renewables north America LLC Development-Western Region 53 SW Yamhill Street, Portland OR 97204 will.talbott@epdr.com

RE: Transmittal of Executable Standard PPA

Blue Marmot V project, a proposed 10 megawatt solar QF

Dear Will,

Thank you for your interest in entering into a Standard Power Purchase Agreement (Standard PPA) with Portland General Electric (PGE). PGE received your written request for an executable Standard PPA on December 21, 2016. PGE has determined that you have provided sufficient information to allow PGE to prepare an executable Standard PPA.

Enclosed please find an executable Standard PPA for your Blue Marmot V project, a proposed 10 megawatt solar generating facility that was self-certified as a qualifying facility (QF) pursuant to 18 CFR 292.207 on September 9, 2016. PGE understands that Blue Marmot V LLC (Seller) is a Limited Liability Corporation formed under the laws of the State of Delaware is the owner of the Blue Marmot V project and will be the Seller under the Standard PPA. If any of the information contained in the enclosed executable Standard PPA is incorrect, please inform PGE immediately and do not execute the agreement.

If Seller executes the enclosed agreement without alteration and returns the partially executed agreement to PGE for full execution, Seller will have established a legally enforceable obligation. Seller is entitled to receive PGE's [Standard Avoided Costs **OR** Renewable Avoided Costs] in effect at the time Seller executes the enclosed agreement without alteration. If the PGE [Standard Avoided Costs **OR** Renewable Avoided Costs] in effect on the date Seller executes the enclosed agreement are different from the [Standard Avoided Costs **OR** Renewable Avoided Costs] reflected in the enclosed agreement, then Seller must send PGE a written request to revise the enclosed agreement to reflect the then applicable [Standard Avoided Costs **OR** Renewable Avoided Costs]. No Standard PPA between PGE and Seller will be valid or binding if it contains [Standard Avoided Costs OR Renewable Avoided Costs] that differ from those in effect on the date the Seller executes the Standard PPA.

Blue Marmot V 01/12/2017 Page 2 of 2

Seller is not authorized to revise the enclosed agreement. If Seller seeks any changes, you will need to send PGE a written request for a new agreement. If you have proposed substantive changes to your project or to the variable term of the executable Standard PPA, PGE will treat the proposal as a request for a new draft Standard PPA and, within 15 business days of receiving your written request for changes, PGE will send you either a new draft Standard PPA or a request for additional or clarifying information. If you have proposed ministerial, typographical, or other non-substantive changes to the enclosed executable Standard PPA, then within 15 business days of receiving your written request for changes, PGE will send you either a revised executable Standard PPA or a request for additional or clarifying information.

This letter summarizes certain aspects of the Standard PPA process; it does not address every detail of the process. Additional details will be provided for each stage in PGE's letters associated with each stage. If you have any questions, please contact PGE's Power Production Coordinator at (503) 464-7013.

incerely.

Shawn P Davis
Project Manager

Portland General Electric

enclosure: Executable Standard PPA for Blue Marmot V LLC's Blue Marmot V Project

cc: Blue Marmot V LLC

c/o EDP Renewables North America LLC; Attention: General Counsel

808 Travis, Suite 700 Houston, Texas 77002



January 12, 2017

Will Talbott EDP Renewables north America LLC Development-Western Region 53 SW Yamhill Street, Portland OR 97204 will.talbott@epdr.com

RE: Transmittal of Executable Standard PPA

Blue Marmot VI project, a proposed 10 megawatt solar QF

Dear Will,

Thank you for your interest in entering into a Standard Power Purchase Agreement (Standard PPA) with Portland General Electric (PGE). PGE received your written request for an executable Standard PPA on December 21, 2016. PGE has determined that you have provided sufficient information to allow PGE to prepare an executable Standard PPA.

Enclosed please find an executable Standard PPA for your Blue Marmot VI project, a proposed 10 megawatt solar generating facility that was self-certified as a qualifying facility (QF) pursuant to 18 CFR 292.207 on September 9, 2016. PGE understands that Blue Marmot VI LLC (Seller) is a Limited Liability Corporation formed under the laws of the State of Delaware is the owner of the Blue Marmot VI project and will be the Seller under the Standard PPA. If any of the information contained in the enclosed executable Standard PPA is incorrect, please inform PGE immediately and do not execute the agreement.

If Seller executes the enclosed agreement without alteration and returns the partially executed agreement to PGE for full execution, Seller will have established a legally enforceable obligation. Seller is entitled to receive PGE's [Standard Avoided Costs OR Renewable Avoided Costs] in effect at the time Seller executes the enclosed agreement without alteration. If the PGE [Standard Avoided Costs OR Renewable Avoided Costs] in effect on the date Seller executes the enclosed agreement are different from the [Standard Avoided Costs OR Renewable Avoided Costs] reflected in the enclosed agreement, then Seller must send PGE a written request to revise the enclosed agreement to reflect the then applicable [Standard Avoided Costs OR Renewable Avoided Costs]. No Standard PPA between PGE and Seller will be valid or binding if it contains [Standard Avoided Costs OR Renewable Avoided Costs] that differ from those in effect on the date the Seller executes the Standard PPA.

Blue Marmot VI 01/12/2017 Page 2 of 2

Seller is not authorized to revise the enclosed agreement. If Seller seeks any changes, you will need to send PGE a written request for a new agreement. If you have proposed substantive changes to your project or to the variable term of the executable Standard PPA, PGE will treat the proposal as a request for a new draft Standard PPA and, within 15 business days of receiving your written request for changes, PGE will send you either a new draft Standard PPA or a request for additional or clarifying information. If you have proposed ministerial, typographical, or other non-substantive changes to the enclosed executable Standard PPA, then within 15 business days of receiving your written request for changes, PGE will send you either a revised executable Standard PPA or a request for additional or clarifying information.

This letter summarizes certain aspects of the Standard PPA process; it does not address every detail of the process. Additional details will be provided for each stage in PGE's letters associated with each stage. If you have any questions, please contact PGE's Power Production Coordinator at (503) 464-7013.

Sincerely,

Project Manager

Portland General Electric

enclosure: Executable Standard PPA for Blue Marmot VI LLC's Blue Marmot VI Project

cc: Blue Marmot VI LLC

c/o EDP Renewables North America LLC; Attention: General Counsel

808 Travis, Suite 700 Houston, Texas 77002 Blue Marmot/201 Talbott/6 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

STANDARD RENEWABLE OFF-SYSTEM VARIABLE POWER PURCHASE AGREEMENT

THIS AGREEMENT is between <u>Blue Marmot VI LLC</u> ("Seller") and Portland General Electric Company ("PGE") (hereinafter each a "Party" or collectively, "Parties") and is effective upon execution by both Parties ("Effective Date").

RECITALS

Seller intends to construct, own, operate and maintain a <u>Solar</u> facility for the generation of electric power located in <u>Lake</u>, County, <u>Oregon @ W 120.498</u>, N 42.122 with a Nameplate Capacity Rating of <u>10000</u> kilowatt ("kW"), as further described in Exhibit A ("Facility"); and

Seller intends to operate the Facility as a "Qualifying Facility," as such term is defined in Section 3.1.3, below.

Seller shall sell and PGE shall purchase the entire Net Output, as such term is defined in Section 1.21, below, from the Facility in accordance with the terms and conditions of this Agreement.

AGREEMENT

NOW, THEREFORE, the Parties mutually agree as follows:

SECTION 1: DEFINITIONS

When used in this Agreement, the following terms shall have the following meanings:

- 1.1. "As-built Supplement" means the supplement to Exhibit A provided by Seller in accordance with Section 4.3 following completion of construction of the Facility, describing the Facility as actually built.
- 1.2. "Base Hours" is defined as the total number of hours in each Contract Year (8,760 or 8,784 for leap year)
- 1.3. "Billing Period" means from the start of the first day of each calendar month to the end of the last day of each calendar month.
- 1.4. "Cash Escrow" means an agreement by two parties to place money into the custody of a third party for delivery to a grantee only after the fulfillment of the conditions specified.
- 1.5. "Commercial Operation Date" means the date that the Facility is deemed by PGE to be fully operational and reliable. PGE may, at its discretion require, among other things, that all of the following events have occurred:
- 1.5.1. (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from a Licensed

Blue Marmot/201 Talbott/7 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

Professional Engineer ("LPE") acceptable to PGE in its reasonable judgment stating that the Facility is able to generate electric power reliably in accordance with the terms and conditions of this Agreement (certifications required under this Section 1.5 can be provided by one or more LPEs);

- 1.5.2. Start-Up Testing of the Facility has been completed in accordance with Section 1.36;
- 1.5.3. (facilities with nameplate under 500 kW exempt from following requirement) After PGE has received notice of completion of Start-Up Testing, PGE has received a certificate addressed to PGE from an LPE stating that the Facility has operated for testing purposes under this Agreement and was continuously mechanically available for operation for a minimum of 120 hours. The Facility must provide ten (10) working days written notice to PGE prior to the start of the initial testing period. If the mechanical availability of the Facility is interrupted during this initial testing period or any subsequent testing period, the Facility shall promptly start a new Test Period and provide PGE forty-eight (48) hours written notice prior to the start of such testing period;
- 1.5.4. (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from an LPE stating that all required interconnection facilities have been constructed and all required interconnection tests have been completed;
- 1.5.5. (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from an LPE stating that Seller has obtained all Required Facility Documents and, if requested by PGE in writing, has provided copies of any or all such requested Required Facility Documents;
- 1.5.6. PGE has received a copy of the executed Generation Interconnection and Transmission Agreements.
- 1.6. "Contract Price" means the applicable price, including on-peak and off-peak prices, as specified in the Schedule.
- 1.7. "Contract Year" means each twelve (12) month period commencing upon the Commercial Operation Date or its anniversary during the Term, except the final Contract Year will be the period from the last anniversary of the Commercial Operation Date during the Term until the end of the Term.
 - 1.8. "Effective Date" has the meaning set forth in Section 2.1.
- 1.9. "Environmental Attributes" shall mean any and all claims, credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical or other substance to the air, soil or water. Environmental Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil or water such as (subject to the foregoing) sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; and (2) any avoided emissions of carbon dioxide (CO2), methane (CH4), and other greenhouse gasses (GHGs) that have been determined by the United Nations

Intergovernmental Panel on Climate Change to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere.

- 1.10. "Facility" has the meaning set forth in the Recitals.
- 1.11. "Generation Interconnection Agreement" means an agreement governing the interconnection of the Facility with **PacifiCorp** electric system.
- 1.12. "Generation Unit" means each separate electrical generator that contributes toward Nameplate Capacity Rating included in Exhibit A. For solar facilities, a generating unit is a complete solar electrical generation system within the Facility that is able to generate and deliver energy to the Point of Delivery independent of other Generation Units within the same Facility.
- 1.13. "Letter of Credit" means an engagement by a bank or other person made at the request of a customer that the issuer will honor drafts or other demands for payment upon compliance with the conditions specified in the letter of credit.
- 1.14. "Licensed Professional Engineer" or "LPE" means a person who is licensed to practice engineering in the state where the Facility is located, who has no economic relationship, association, or nexus with the Seller, and who is not a representative of a consulting engineer, contractor, designer or other individual involved in the development of the Facility, or of a manufacturer or supplier of any equipment installed in the Facility. Such Licensed Professional Engineer shall be licensed in an appropriate engineering discipline for the required certification being made and be acceptable to PGE in its reasonable judgment.
- 1.15. "Lost Energy" means "Lost Energy" means ((the Guarantee of Mechanical Availability as set forth in 3.1.10 / MAP) X Net Output for a Calendar Year) Net Output for the Calendar Year. Lost Energy shall be zero unless the result of the calculation in this subsection results in a positive number.
- 1.16. "Lost Energy Value" means Lost Energy X the excess of the annual time-weighted average Mid-C Index Price for On Peak Hours and Off Peak Hours over the time weighted average Contract Price for On Peak and Off Peak Hours for the corresponding time period (provided that such excess shall not exceed the Contract Price and further provided that Lost Energy is deemed to be zero prior to reaching the Commercial Operation Date) plus any reasonable costs incurred by PGE to purchase replacement power and/or transmission to deliver the replacement power to the Point of Delivery (For Start-Up Lost Energy Value See 1.35).
- 1.17. "Mechanical Availability Percentage" or "MAP" shall mean that percentage for any Contract Year for the Facility calculated in accordance with the following formula:

MAP = 100 X (Operational Hours) /(Base Hours X Number of Units)

1.18. "Mid-C Index Price" means the Day Ahead Intercontinental Exchange ("ICE") index price for the bilateral OTC market for energy at the Mid-C Physical for Average On Peak Power and Average Off Peak Power found on the following website:

Blue Marmot/201 Talbott/9 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

https://www.theice.com/products/OTC/Physical-Energy/Electricity. In the event ICE no longer publishes this index, PGE and the Seller agree to select an alternative successor index representative of the Mid-C trading hub.

- 1.19. "Nameplate Capacity Rating" means the maximum capacity of the Facility as stated by the manufacturer, expressed in kW, which shall not exceed 10,000 kW.
- 1.20. "Net Dependable Capacity" means the maximum capacity the Facility can sustain over a specified period modified for seasonal limitations, if any, and reduced by the capacity required for station service or auxiliaries.
- 1.21. "Net Output" means all energy expressed in kWhs produced by the Facility, less station and other onsite use and less transformation and transmission losses.
- 1.22. "Number of Units" means the number of Generation Units in the Facility as specified in Exhibit A.
 - 1.23. "Off-Peak Hours" has the meaning provided in the Schedule.
 - 1.24. "On-Peak Hours" has the meaning provided in the Schedule.
- 1.25. "Operational Hours" for the Facility means the total across all Generation Units of the number of hours each of the Facility's Generation Units are potentially capable of producing power at its Nameplate Capacity Rating regardless of actual weather conditions, season and the time of day or night, without any mechanical operating constraint or restriction, and potentially capable of delivering such power to the Point of Delivery in a Contract Year. During up to, but not more than, two hundred (200) hours of Planned Maintenance during a Contract Year for each Generation Unit and hours during which an event of Force Majeure exists, a Generation Unit shall be considered potentially capable of delivering such power to the Point of Delivery. For example, in the absence of any Planned Maintenance beyond 200 hours on any Generation Unit or Event of Force Majeure, the Operational Hours for a wind farm with five (5) separate two (2) MW turbines would be 43,800 for a Contract Year.
- 1.26. "Planned Maintenance" means outages scheduled ninety (90) days in advance, with PGE's prior written consent, which shall not be unreasonably withheld.
 - 1.27. "Point of Delivery" means the PGE system.
- 1.28. "Pre-Commercial Operation Date Minimum Net Output" shall mean, unless such MWh is specifically set forth by Seller in Exhibit A, an amount in MWh equal to seventy-five percent (75%) of Nameplate Capacity Rating X thirty percent (30%) for a wind or other renewable QF or fifty percent (50%) for a solar QF X (whole months since the date selected in Section 2.2.1 / 12) X (8760 hours 200 hours (assumed Planned Maintenance)) for each month. If Seller has provided specific expected monthly Net Output amounts for the Facility in Exhibit A, "Pre-Commercial Operation Date Minimum Net Output" shall mean seventy-five percent (75%) X expected net output set forth in Exhibit A for each month.

Blue Marmot/201 Talbott/10 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

- 1.29. "Prime Rate" means the publicly announced prime rate or reference rate for commercial loans to large businesses with the highest credit rating in the United States in effect from time to time quoted by Citibank, N.A. If a Citibank, N.A. prime rate is not available, the applicable Prime Rate shall be the announced prime rate or reference rate for commercial loans in effect from time to time quoted by a bank with \$10 billion or more in assets in New York City, N.Y., selected by the Party to whom interest based on the prime rate is being paid.
- 1.30. "Prudent Electrical Practices" means those practices, methods, standards and acts engaged in or approved by a significant portion of the electric power industry in the Western Electricity Coordinating Council that at the relevant time period, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with good business practices, reliability, economy, safety and expedition, and which practices, methods, standards and acts reflect due regard for operation and maintenance standards recommended by applicable equipment suppliers and manufacturers, operational limits, and all applicable laws and regulations. Prudent Electrical Practices are not intended to be limited to the optimum practice, method, standard or act to the exclusion of all others, but rather to those practices, methods and acts generally acceptable or approved by a significant portion of the electric power generation industry in the relevant region, during the relevant period, as described in the immediate preceding sentence.
- 1.31. "Required Facility Documents" means all licenses, permits, authorizations, and agreements necessary for construction, operation, interconnection, and maintenance of the Facility including without limitation those set forth in Exhibit B.
- 1.32. "RPS Attributes" means all attributes related to the Net Output generated by the Facility that are required in order to provide PGE with "qualifying electricity," as that term is defined in Oregon's Renewable Portfolio Standard Act, Ore. Rev. Stat. 469A.010, in effect at the time of execution of this Agreement. RPS Attributes do not include Environmental Attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity and not needed to ensure that there are zero net emissions associated with the generation of electricity.
- 1.33. "Schedule" shall mean PGE Schedule 201 filed with the Oregon Public Utilities Commission ("Commission") in effect on the Effective Date of this Agreement and attached hereto as Exhibit D, the terms of which are hereby incorporated by reference.
- 1.34. "Senior Lien" means a prior lien which has precedence as to the property under the lien over another lien or encumbrance
- 1.35. "Start-Up Lost Energy Value" means for the period after the date specified in Section 2.2.2 but prior to achievement of the Commercial Operation Date: zero, unless the Net Output is less than the pro-rated Pre-Commercial Operation Date Minimum Net Output for the applicable delay period, and the time-weighted average of the delay period's Mid-C Index Price for On-Peak Hours and Off-Peak Hours is greater

than the time-weighted average of the delay period's Contract Price for On-Peak Hours and Off-Peak Hours, in which case Startup Lost Energy Value equals: (pro-rated Pre-Commercial Operation Date Minimum Net Output for the applicable period - Net Output for the applicable period) X (the lower of: the time-weighted average of the Contract Price for On-Peak hours and Off-Peak Hours during the applicable period; or (the time-weighted average of the Mid-C Index Price for On-Peak Hours and Off-Peak Hours during the applicable period). The time-weighted average in this section will reflect the relative proportions of On-Peak Hours and Off-Peak Hours in each day.

- 1.36. "Start-Up Testing" means the completion of applicable required factory and start-up tests as set forth in Exhibit C.
- 1.37. "Step-in Rights" means the right of one party to assume an intervening position to satisfy all terms of an agreement in the event the other party fails to perform its obligations under the agreement.
- 1.38. "Term" shall mean the period beginning on the Effective Date and ending on the Termination Date.
- 1.39. "Test Period" shall mean a period of sixty (60) days or a commercially reasonable period determined by the Seller.
- 1.40. "Transmission Agreement" means an agreement executed by the Seller and the Transmission Provider(s) for Transmission Services.
- 1.41. "Transmission Curtailment" means a limitation on Seller's ability to deliver any portion of the scheduled energy to PGE due to the unavailability of transmission to the Point of Delivery (for any reason other than Force Majeure).
- 1.42. "Transmission Curtailment Replacement Energy Cost" means the greater of zero or the amount calculated as: ((Mid-C Index Price Contract Price) X curtailed energy) for periods of Transmission Curtailment.
- 1.43. "Transmission Provider(s)" means the signatory (other than the Seller) to the Transmission Agreement.
- 1.44. "Transmission Services" means any and all services (including but not limited to ancillary services and control area services) required for the firm transmission and delivery of Energy from the Facility to the Point of Delivery for a term not less than the Term of this Agreement.

References to Recitals, Sections, and Exhibits are to be the recitals, sections and exhibits of this Agreement.

SECTION 2: TERM; COMMERCIAL OPERATION DATE

2.1. This Agreement shall become effective upon execution by both Parties ("Effective Date").

- 2.2. Time is of the essence of this Agreement, and Seller's ability to meet certain requirements prior to the Commercial Operation Date and to complete all requirements to establish the Commercial Operation Date is critically important. Therefore,
- 2.2.1. By **November 1, 2019** Seller shall begin initial deliveries of Net Output; and
- 2.2.2. By **November 30, 2019** Seller shall have completed all requirements under Section 1.5 and shall have established the Commercial Operation Date.
- 2.2.3. Unless the Parties agree in writing that a later Commercial Operation Date is reasonable and necessary, the Commercial Operation Date shall be no more than three (3) years from the Effective Date. PGE will not unreasonably withhold agreement to a Commercial Operation Date that is more than three (3) years from the Effective date if the Seller has demonstrated that a later Commercial Operation Date is reasonable and necessary.
- 2.3. This Agreement shall terminate on <u>18 years after effective date</u>, or the date the Agreement is terminated in accordance with Section 8 or 11, whichever is earlier ("Termination Date").

<u>SECTION 3: REPRESENTATIONS AND WARRANTIES</u>

- 3.1. Seller and PGE represent, covenant, and warrant as follows:
- 3.1.1. Seller warrants it is a <u>Limited liability company</u> duly organized under the laws of <u>Delaware</u>.
- 3.1.2. Seller warrants that the execution and delivery of this Agreement does not contravene any provision of, or constitute a default under, any indenture, mortgage, or other material agreement binding on Seller or any valid order of any court, or any regulatory agency or other body having authority to which Seller is subject.
- 3.1.3. Seller warrants that the Facility is and shall for the Term of this Agreement continue to be a "Qualifying Facility" ("QF") as that term is defined in the version of 18 C.F.R. Part 292 in effect on the Effective Date. Seller has provided the appropriate QF certification, which may include a Federal Energy Regulatory Commission ("FERC") self-certification to PGE prior to PGE's execution of this Agreement. At any time during the Term of this Agreement, PGE may require Seller to provide PGE with evidence satisfactory to PGE in its reasonable discretion that the Facility continues to qualify as a QF under all applicable requirements.
- 3.1.4. Seller warrants that it has not within the past two (2) years been the debtor in any bankruptcy proceeding, and Seller is and will continue to be for the Term of this Agreement current on all of its financial obligations.
- 3.1.5. Seller warrants that during the Term of this Agreement, all of Seller's right, title and interest in and to the Facility shall be free and clear of all liens and encumbrances other than liens and encumbrances arising from third-party financing of the Facility other than workers', mechanics', suppliers' or similar liens, or tax liens, in

each case arising in the ordinary course of business that are either not yet due and payable or that have been released by means of a performance bond acceptable to PGE posted within eight (8) calendar days of the commencement of any proceeding to foreclose the lien.

- 3.1.6. Seller warrants that it will design and operate the Facility consistent with Prudent Electrical Practices.
- 3.1.7. Seller warrants that the Facility has a Nameplate Capacity Rating not greater than 10,000 kW.
 - 3.1.8. Seller warrants that Net Dependable Capacity of the Facility is **10,000** kW.
- 3.1.9. Seller estimates that the average annual Net Output to be delivered by the Facility to PGE is <u>21,921,601</u> kilowatt-hours ("kWh"), which amount PGE will include in its resource planning.
- 3.1.10. Seller represents and warrants that the Facility shall achieve the following Mechanical Availability Percentages ("Guarantee of Mechanical Availability"):
- 3.1.10.1. Ninety percent (90%) beginning in the first Contract Year and extending through the Term for the Facility, if the Facility was operational and sold electricity to PGE or another buyer prior to the Effective Date of this Agreement; or
- 3.1.10.2. Ninety percent (90%) beginning in Contract Year three and extending throughout the remainder of the Term.
- 3.1.10.3. Annually, within 90 days of the end of each Contract Year, Seller shall send to PGE a detailed written report demonstrating and providing evidence of the actual MAP for the previous Contract Year.
- 3.1.10.4. Seller's failure to meet the Guarantee of Mechanical Availability in a Calendar Year shall result in damages payable to PGE by Seller equal to the Lost Energy Value. PGE shall bill Seller for such damages in accordance with Section 7.
- 3.1.11. Seller will deliver from the Facility to PGE at the Point of Delivery Net Output not to exceed a maximum of <u>33,750,000</u> kWh of Net Output during each Contract Year ("Maximum Net Output"). The cost of delivering energy from the Facility to PGE is the sole responsibility of the Seller.
- 3.1.12. By the Commercial Operation Date, Seller has entered into a Generation Interconnection Agreement for a term not less than the term of this Agreement.
- 3.1.13. PGE warrants that it has not within the past two (2) years been the debtor in any bankruptcy proceeding, and PGE is and will continue to be for the Term of this Agreement current on all of its financial obligations.
- 3.1.14. Seller warrants that the Facility satisfies the eligibility requirements specified in the Definition of a Small Cogeneration Facility or Small Power Production Facility Eligible to Receive the Standard Renewable Rates and Standard Renewable PPA in PGE's Schedule and Seller will not make any changes in its ownership, control or management during the term of this Agreement that would cause it to not be in

compliance with the Definition of a Small Cogeneration Facility or Small Power Production Facility Eligible to Receive the Standard Renewable Rates and Standard Renewable PPA in PGE's Schedule. Seller will provide, upon request by PGE not more frequently than every 36 months, such documentation and information as may be reasonably required to establish Seller's continued compliance with such Definition. PGE agrees to take reasonable steps to maintain the confidentiality of any portion of the above described documentation and information that the Seller identifies as confidential except PGE will provide all such confidential information to the Commission upon the Commission's request.

3.1.15. Seller warrants that it will comply with all requirements necessary for all Transferred RECs (as defined in Section 4.5) associated with Net Output to be issued, monitored, accounted for, and transferred by and through the Western Renewable Energy Generation System consistent with the provisions of OAR 330-160-0005 through OAR 330-160-0050. PGE warrants that it will reasonably cooperate in Seller's efforts to meet such requirements, including, for example serving as the qualified reporting entity for the Facility if the Facility is located in PGE's balancing authority.

SECTION 4: DELIVERY OF POWER, PRICE AND ENVIRONMENTAL ATTRIBUTES

- 4.1. Commencing on the Effective Date and continuing through the Term of this Agreement, Seller shall sell to PGE the entire Net Output delivered from the Facility at the Point of Delivery.
 - 4.2. PGE shall pay Seller the Contract Price for all delivered Net Output.
- 4.3. Upon completion of construction of the Facility, Seller shall provide PGE an As-built Supplement to specify the actual Facility as built. Seller shall not increase the Nameplate Capacity Rating above that specified in Exhibit A or increase the ability of the Facility to deliver Net Output in quantities in excess of the Net Dependable Capacity, or the Maximum Net Output as described in Section 3.1.11 above, through any means including, but not limited to, replacement, modification, or addition of existing equipment, except with prior written notice to PGE. In the event Seller increases the Nameplate Capacity Rating of the Facility to no more than 10,000 kW pursuant to this section, PGE shall pay the Contract Price for the additional delivered Net Output. In the event Seller increases the Nameplate Capacity Rating to greater than 10,000 kW, then Seller shall be required to enter into a new power purchase agreement for all delivered Net Output proportionally related to the increase of Nameplate Capacity above 10,000 kW.
- 4.4. Seller shall provide preschedules for all deliveries of energy hereunder, including identification of receiving and generating control areas, by 9:00:00 PPT on the last business day prior to the scheduled date of delivery. All energy shall be scheduled according to the most current North America Energy Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) scheduling rules and practices. The Parties' respective representatives shall maintain hourly real-time schedule coordination; provided, however, that in the absence of such coordination, the hourly schedule established by the exchange of preschedules shall be considered final. Seller

Blue Marmot/201 Talbott/15 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

and PGE shall maintain records of hourly energy schedules for accounting and operating purposes. The final E-Tag shall be the controlling evidence of the Parties' schedule. All energy shall be prescheduled according to customary WECC scheduling practices. Seller shall make commercially reasonable efforts to schedule in any hour an amount equal to its expected Net Output for such hour. Seller shall maintain a minimum of two years records of Net Output and shall agree to allow PGE to have access to such records and to imbalance information kept by the Transmission Provider.

From the start of the Renewable Resource Deficiency Period through the remainder of the Term of this Agreement, Seller shall provide and PGE shall acquire the RPS Attributes for the Contract Years as specified in the Schedule and Seller shall retain ownership of all other Environmental Attributes (if any). During the Renewable Resource Sufficiency Period, Seller shall retain all Environmental Attributes in accordance with the Schedule. The Contract Price includes full payment for the Net Output and any RPS Attributes transferred to PGE under this Agreement. With respect to Environmental Attributes not transferred to PGE under this Agreement ("Seller-Retained Environmental Attributes") Seller may report under §1605(b) of the Energy Policy Act of 1992 or under any applicable program as belonging to Seller any of the Seller-Retained Environmental Attributes, and PGE shall not report under such program that such Seller-Retained Environmental Attributes belong to it. With respect to RPS Attributes transferred to PGE under this Agreement ("Transferred RECs"), PGE may report under §1605(b) of the Energy Policy Act of 1992 or under any applicable program as belonging to it any of the Transferred RECs, and Seller shall not report under such program that such Transferred RECs belong to it.

SECTION 5: OPERATION AND CONTROL

- 5.1. Seller shall operate and maintain the Facility in a safe manner in accordance with the Generation Interconnection Agreement, and Prudent Electrical Practices. PGE shall have no obligation to purchase Net Output from the Facility to the extent the interconnection of the Facility to PGE's electric system is disconnected, suspended or interrupted, in whole or in part, pursuant to the Generation Interconnection Agreement, or to the extent generation curtailment is required as a result of Seller's noncompliance with the Generation Interconnection Agreement. Seller is solely responsible for the operation and maintenance of the Facility. PGE shall not, by reason of its decision to inspect or not to inspect the Facility, or by any action or inaction taken with respect to any such inspection, assume or be held responsible for any liability or occurrence arising from the operation and maintenance by Seller of the Facility.
- 5.2. Seller agrees to provide sixty (60) days advance written notice of any scheduled maintenance that would require shut down of the Facility for any period of time.
- 5.3. If the Facility ceases operation for unscheduled maintenance, Seller immediately shall notify PGE of the necessity of such unscheduled maintenance, the time when such maintenance has occurred or will occur, and the anticipated duration of such maintenance. Seller shall take all reasonable measures and exercise its best

Blue Marmot/201 Talbott/16 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

efforts to avoid unscheduled maintenance, to limit the duration of such unscheduled maintenance, and to perform unscheduled maintenance during Off-Peak hours.

SECTION 6: CREDITWORTHINESS

In the event Seller: a) is unable to represent or warrant as required by Section 3 that it has not been a debtor in any bankruptcy proceeding within the past two (2) years; b) becomes such a debtor during the Term; or c) is not or will not be current on all its financial obligations, Seller shall immediately notify PGE and shall promptly (and in no less than 10 days after notifying PGE) provide default security in an amount reasonably acceptable to PGE in one of the following forms: Senior Lien, Step-in Rights, a Cash Escrow or Letter of Credit. The amount of such default security that shall be acceptable to PGE shall be equal to: (annual On Peak Hours) X (On Peak Price – Off Peak Price) X (Net Dependable Capacity). Notwithstanding the foregoing, in the event Seller is not current on construction related financial obligations, Seller shall notify PGE of such delinquency and PGE may, in its discretion, grant an exception to the requirements to provide default security if the QF has negotiated financial arrangements with the construction loan lender that mitigate Seller's financial risk to PGE.

SECTION 7: BILLINGS, COMPUTATIONS AND PAYMENTS

- 7.1. On or before the thirtieth (30th) day following the end of each Billing Period, PGE shall send to Seller payment for Seller's deliveries of Net Output to PGE, together with computations supporting such payment. PGE may offset any such payment to reflect amounts owing from Seller to PGE pursuant to this Agreement and any other agreement related to the Facility between the Parties or otherwise. On or before the thirtieth (30th) day following the end of each Contract Year, PGE shall bill for any Lost Energy Value accrued pursuant to this Agreement.
- 7.2. Any amounts owing after the due date thereof shall bear interest at the Prime Rate plus two percent (2%) from the date due until paid; provided, however, that the interest rate shall at no time exceed the maximum rate allowed by applicable law.

SECTION 8: DEFAULT, REMEDIES AND TERMINATION

- 8.1. In addition to any other event that may constitute a default under this Agreement, the following events shall constitute defaults under this Agreement:
- 8.1.1. Breach by Seller or PGE of a representation or warranty, except for Section 3.1.4, set forth in this Agreement.
- 8.1.2. Seller's failure to provide default security, if required by Section 6, prior to delivery of any Net Output to PGE or within 10 days of notice.
- 8.1.3. Seller's failure to meet the Guarantee of Mechanical Availability established in Section 3.1.10 for two consecutive Contract Years or Seller's failure to provide any written report required by that section.
 - 8.1.4. If Seller is no longer a Qualifying Facility.
 - 8.1.5. Failure of PGE to make any required payment pursuant to Section 7.1.

- 8.1.6. Seller's failure to meet the Commercial Operation Date.
- 8.2. In the event of a default under Section 8.1.6, PGE may provide Seller with written notice of default. Seller shall have one year in which to cure the default during which time the Seller shall pay PGE damages equal to the Lost Energy Value. If Seller is unable to cure the default, PGE may immediately terminate this Agreement as provided in Section 8.3. PGE's resource sufficiency/deficiency position shall have no bearing on PGE's right to terminate the Agreement under this Section 8.2.
- 8.3. In the event of a default hereunder, except as otherwise provided in this Agreement, the non-defaulting party may immediately terminate this Agreement at its sole discretion by delivering written notice to the other Party. In addition, the non-defaulting Party may pursue any and all legal or equitable remedies provided by law or pursuant to this Agreement including damages related to the need to procure replacement power. A termination hereunder shall be effective upon the date of delivery of notice, as provided in Section 20. The rights provided in this Section 8 are cumulative such that the exercise of one or more rights shall not constitute a waiver of any other rights.
- 8.4. If this Agreement is terminated as provided in this Section 8, PGE shall make all payments, within thirty (30) days, that, pursuant to the terms of this Agreement, are owed to Seller as of the time of receipt of notice of default. PGE shall not be required to pay Seller for any Net Output delivered by Seller after such notice of default.
- 8.5. In the event PGE terminates this Agreement pursuant to this Section 8, and Seller wishes to again sell Net Output to PGE following such termination, PGE in its sole discretion may require that Seller shall do so subject to the terms of this Agreement, including but not limited to the Contract Price until the Term of this Agreement (as set forth in Section 2.3) would have run in due course had the Agreement remained in effect. At such time Seller and PGE agree to execute a written document ratifying the terms of this Agreement.
- 8.6. Sections 8.1, 8.4, 8.5, 10, and 19.2 shall survive termination of this Agreement.

SECTION 9: TRANSMISSION CURTAILMENTS

- 9.1. Seller shall give PGE notice as soon as reasonably practicable of any Transmission Curtailment that is likely to affect Seller's ability to deliver any portion of energy scheduled pursuant to Section 4.4 of this Agreement.
- 9.2. If as the result of a Transmission Curtailment, Seller does not deliver any portion of energy (including real-time adjustments), scheduled pursuant to Section 4.4 of this Agreement, Seller shall pay PGE the Transmission Curtailment Replacement Energy Cost for the number of MWh of energy reasonably determined by PGE as the difference between (i) the scheduled energy that would have been delivered to PGE under this Agreement during the period of Transmission Curtailment and (ii) the actual energy, if any, that was delivered to PGE for the period.

Blue Marmot/201 Talbott/18 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

SECTION 10: INDEMNIFICATION AND LIABILITY

- 10.1. Seller agrees to defend, indemnify and hold harmless PGE, its directors, officers, agents, and representatives against and from any and all loss, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with Seller's delivery of electric power to PGE or with the facilities at or prior to the Point of Delivery, or otherwise arising out of this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PGE, Seller or others, excepting to the extent such loss, claim, action or suit may be caused by the negligence of PGE, its directors, officers, employees, agents or representatives.
- 10.2. PGE agrees to defend, indemnify and hold harmless Seller, its directors, officers, agents, and representatives against and from any and all loss, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with PGE's receipt of electric power from Seller or with the facilities at or after the Point of Delivery, or otherwise arising out of this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PGE, Seller or others, excepting to the extent such loss, claim, action or suit may be caused by the negligence of Seller, its directors, officers, employees, agents or representatives.
- 10.3. Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a Party to this Agreement. No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or to the public, nor affect the status of PGE as an independent public utility corporation or Seller as an independent individual or entity.
- 10.4. NEITHER PARTY SHALL BE LIABLE TO THE OTHER FOR SPECIAL, PUNITIVE, INDIRECT OR CONSEQUENTIAL DAMAGES, WHETHER ARISING FROM CONTRACT, TORT (INCLUDING NEGLIGENCE), STRICT LIABILITY OR OTHERWISE.

SECTION 11: INSURANCE

11.1. Prior to the connection of the Facility to PGE's electric system, provided such Facility has a design capacity of 200 kW or more, Seller shall secure and continuously carry for the Term hereof, with an insurance company or companies rated not lower than "B+" by the A. M. Best Company, insurance policies for bodily injury and property damage liability. Such insurance shall include provisions or endorsements naming PGE, it directors, officers and employees as additional insureds; provisions that such insurance is primary insurance with respect to the interest of PGE and that any insurance or self-insurance maintained by PGE is excess and not contributory insurance with the insurance required hereunder; a cross-liability or severability of

Blue Marmot/201 Talbott/19 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

insurance interest clause; and provisions that such policies shall not be canceled or their limits of liability reduced without thirty (30) days' prior written notice to PGE. Initial limits of liability for all requirements under this section shall be \$1,000,000 million single limit, which limits may be required to be increased or decreased by PGE as PGE determines in its reasonable judgment economic conditions or claims experience may warrant.

- 11.2. Prior to the connection of the Facility to PGE's electric system, provided such facility has a design capacity of 200 kW or more, Seller shall secure and continuously carry for the Term hereof, in an insurance company or companies rated not lower than "B+" by the A. M. Best Company, insurance acceptable to PGE against property damage or destruction in an amount not less than the cost of replacement of the Facility. Seller promptly shall notify PGE of any loss or damage to the Facility. Unless the Parties agree otherwise, Seller shall repair or replace the damaged or destroyed Facility, or if the facility is destroyed or substantially destroyed, it may terminate this Agreement. Such termination shall be effective upon receipt by PGE of written notice from Seller. Seller shall waive its insurers' rights of subrogation against PGE regarding Facility property losses.
- 11.3. Prior to the connection of the Facility to PGE's electric system and at all other times such insurance policies are renewed or changed, Seller shall provide PGE with a copy of each insurance policy required under this Section, certified as a true copy by an authorized representative of the issuing insurance company or, at the discretion of PGE, in lieu thereof, a certificate in a form satisfactory to PGE certifying the issuance of such insurance. If Seller fails to provide PGE with copies of such currently effective insurance policies or certificates of insurance, PGE at its sole discretion and without limitation of other remedies, may upon ten (10) days advance written notice by certified or registered mail to Seller either withhold payments due Seller until PGE has received such documents, or purchase the satisfactory insurance and offset the cost of obtaining such insurance from subsequent power purchase payments under this Agreement.

SECTION 12: FORCE MAJEURE

12.1. As used in this Agreement, "Force Majeure" or "an event of Force Majeure" means any cause beyond the reasonable control of the Seller or of PGE which, despite the exercise of due diligence, such Party is unable to prevent or overcome. By way of example, Force Majeure may include but is not limited to acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes, and other labor disturbances, earthquakes, fires, lightning, epidemics, sabotage, restraint by court order or other delay or failure in the performance as a result of any action or inaction on behalf of a public authority which by the exercise of reasonable foresight such Party could not reasonably have been expected to avoid and by the exercise of due diligence, it shall be unable to overcome, subject, in each case, to the requirements of the first sentence of this paragraph. Force Majeure, however, specifically excludes the cost or availability of resources to operate the Facility, changes in market conditions that affect

Blue Marmot/201 Talbott/20 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

the price of energy or transmission, wind or water droughts, and obligations for the payment of money when due.

- 12.2. If either Party is rendered wholly or in part unable to perform its obligation under this Agreement because of an event of Force Majeure, that Party shall be excused from whatever performance is affected by the event of Force Majeure to the extent and for the duration of the Force Majeure, after which such Party shall recommence performance of such obligation, provided that:
- 12.2.1. the non-performing Party, shall, promptly, but in any case within one (1) week after the occurrence of the Force Majeure, give the other Party written notice describing the particulars of the occurrence; and
- 12.2.2. the suspension of performance shall be of no greater scope and of no longer duration than is required by the Force Majeure; and
- 12.2.3. the non-performing Party uses its best efforts to remedy its inability to perform its obligations under this Agreement.
- 12.3. No obligations of either Party which arose before the Force Majeure causing the suspension of performance shall be excused as a result of the Force Majeure.
- 12.4. Neither Party shall be required to settle any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to the Party's best interests.

SECTION 13: SEVERAL OBLIGATIONS

Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership or joint venture or to impose a trust or partnership duty, obligation or liability between the Parties. If Seller includes two or more parties, each such party shall be jointly and severally liable for Seller's obligations under this Agreement.

SECTION 14: CHOICE OF LAW

This Agreement shall be interpreted and enforced in accordance with the laws of the state of Oregon, excluding any choice of law rules which may direct the application of the laws of another jurisdiction.

SECTION 15: PARTIAL INVALIDITY AND PURPA REPEAL

It is not the intention of the Parties to violate any laws governing the subject matter of this Agreement. If any of the terms of the Agreement are finally held or determined to be invalid, illegal or void as being contrary to any applicable law or public policy, all other terms of the Agreement shall remain in effect. If any terms are finally held or determined to be invalid, illegal or void, the Parties shall enter into negotiations concerning the terms affected by such decision for the purpose of achieving conformity with requirements of any applicable law and the intent of the Parties to this Agreement.

In the event the Public Utility Regulatory Policies Act (PURPA) is repealed, this Agreement shall not terminate prior to the Termination Date, unless such termination is mandated by state or federal law.

SECTION 16: WAIVER

Any waiver at any time by either Party of its rights with respect to a default under this Agreement or with respect to any other matters arising in connection with this Agreement must be in writing, and such waiver shall not be deemed a waiver with respect to any subsequent default or other matter.

SECTION 17: GOVERNMENTAL JURISDICTION AND AUTHORIZATIONS

This Agreement is subject to the jurisdiction of those governmental agencies having control over either Party or this Agreement. Seller shall at all times maintain in effect all local, state and federal licenses, permits and other approvals as then may be required by law for the construction, operation and maintenance of the Facility, and shall provide upon request copies of the same to PGE.

SECTION 18: SUCCESSORS AND ASSIGNS

This Agreement and all of the terms hereof shall be binding upon and inure to the benefit of the respective successors and assigns of the Parties. No assignment hereof by either Party shall become effective without the written consent of the other Party being first obtained and such consent shall not be unreasonably withheld. Notwithstanding the foregoing, either Party may assign this Agreement without the other Party's consent as part of (a) a sale of all or substantially all of the assigning Party's assets, or (b) a merger, consolidation or other reorganization of the assigning Party.

SECTION 19: ENTIRE AGREEMENT

- 19.1. This Agreement supersedes all prior agreements, proposals, representations, negotiations, discussions or letters, whether oral or in writing, regarding PGE's purchase of Net Output from the Facility. No modification of this Agreement shall be effective unless it is in writing and signed by both Parties.
- 19.2. By executing this Agreement, Seller releases PGE from any third party claims related to the Facility, known or unknown, which may have arisen prior to the Effective Date.

SECTION 20: NOTICES

20.1. All notices except as otherwise provided in this Agreement shall be in writing, shall be directed as follows and shall be considered delivered if delivered in person or when deposited in the U.S. Mail, postage prepaid by certified or registered mail and return receipt requested:

To Seller: Blue Marmot VI LLC

c/o EDP Renewables North America LLC;

Attention: General Counsel

808 Travis, Suite 700 Houston, Texas 77002 Blue Marmot/201 Talbott/22 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

	To PGE:	Contracts Manager QF Contracts, 3WTC0306 PGE - 121 SW Salmon St. Portland, Oregon 97204
or thei 20.		may change the person to whom such notices are addressed, oviding written notices thereof in accordance with this Section
execu		REOF, the Parties hereto have caused this Agreement to be re names as of the Effective Date.
PGE		
By:		
Name	·	
Title: _		
Date:_		
	Marmot VI LLC	
(Ivame	e Seller)	
By:		
	:	
Title: _		
Date:_		

with a copy to:

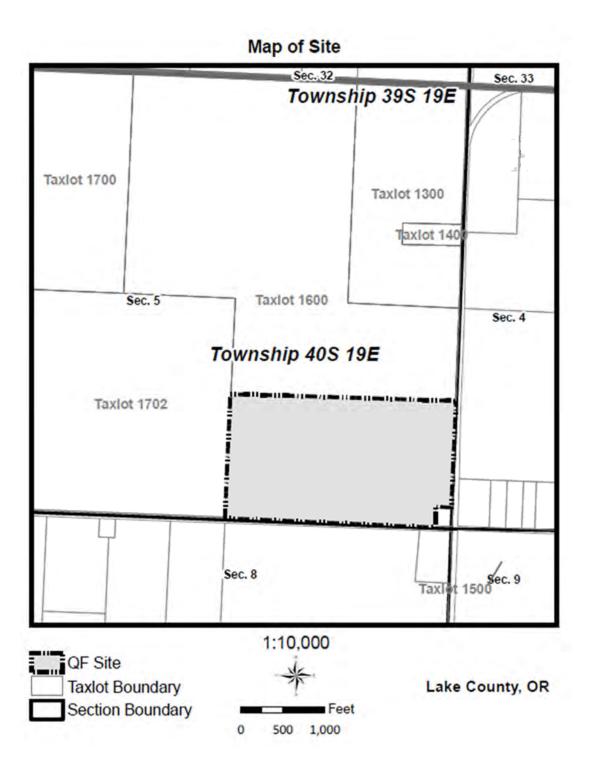
EXHIBIT A DESCRIPTION OF SELLER'S FACILITY

The facility will be a solar PV plant consisting of 39,324 polycrystalline modules of nominal 335W rating each. Total plant rating will be 13.174MWdc/10MWac. Modules will be mounted to single-axis trackers.

Central inverter stations will be located at intermediate points in the PV field. Modules will be evenly distributed to the inverter stations. The total inverter nameplate rating will be 10.0MWac. Each inverter will be directly coupled to a 34.5kV step-up transformer. The transformers will be connected to a 34.5kV AC collection system, which will feed into the plant switchgear.

The plant switchgear will feed a 34.5kV transmission line, which will run overhead approximately 11.1 miles to the PacifiCorp Mile-Hi Substation. Inside the Mile-Hi Substation, the transmission line will connect to a new bay containing a facility-owned 34.5kV/115kV GSU transformer, associated breakers, switching, bus, and controls.

The facility-owned components at Mile-Hi substation are considered part of the selfcertified qualifying facility.



 $Blue\ Marmot/201$ Talbott/25 $Schedule\ 201$ $Standard\ Renewable\ Off-System\ Variable\ Power\ Purchase\ Agreement$ $Form\ Effective\ August\ 12,\ 2016$

Monthly Hou	ally sum:	for E_Grid	d (MWh)																									
	OH	1H	2H	3H	4H	5H	6H	1 7	H	8H	9H	10H	11H	12H	13H	14H	15H	16H	17H	1	18H 13	H 2	20H	21H	22H	23	Н	Total
January		0	0	0	0	0	0	0	0	66	132	125	124	114	118	12	7 10	0	13	0	0	0		0	0	0	0	923
February		0	0	0	0	0	0	0	14	100	141	1 142	143	3 140	150	15	8 15	3	67	0	0	0		0	0	0	0	1208
March		0	0	0	0	0	0	6	93	173	195	192	197	7 184	188	17	B 15	9	137	36	0	0		0	0	0	0	1738
April		0	0	0	0	0	0	86	195	202	21	1 225	22	7 235	220	20	7 19	0	173	85	0	0		0	0	0	0	2256
May		0	0	0	0	0	53	182	231	249	258	264	253	3 246	236	24	4 23	0 2	220	167	46	0		0	0	0	0	2879
June		0	0	0	0	0	98	241	259	264	268	269	254	254	25	1 24	8 2	¥1 2	226	203	78	0		0	0	0	0	3154
July		0	0	0	0	0	63	203	243	251	260	266	267	26	254	25	5 24	8 2	236	194	74	0		0	0	0	0	3070
August		0	0	0	0	0	4	130	257	268	277	274	255	257	25	1 24	9 23	8 2	232	156	29	0		0	0	0	0	2877
September		0	0	0	0	0	0	73	212	237	244	244	225	225	220	23	0 22	14	175	46	0	0		0	0	0	0	2355
October		0	0	0	0	0	0	2	109	187	187	192	184	197	212	22	6 19	19	72	0	0	0		0	0	0	0	1767
November		0	0	0	0	0	0	0	25	96	119	117	116	116	135	13	1 7	7	1	0	0	0		0	0	0	0	933
December		0	0	0	0	0	0	0	0	54	103	102	105	103	11	1 12	2 6	14	0	0	0	0		0	0	0	0	764
Year		-2	-2	-2	-2	-2	216	923	1637	2146	2396	241	2345	2332	2347	237	5 212	5 15	552	886	226	-2		-2	-2	-2	-2	23903

EXHIBIT B REQUIRED FACILITY DOCUMENTS

Sellers Generation Interconnection Agreement

Transmission Service Agreement with PacifiCorp

Purchase option agreement

Conditional Use Permit issued by Lake County

Any additional permits that might be required by Lake County or Oregon Department of Environmental Quality, including access permit, building and electric permits, and storm water prevention permit

FERC Qualifying Facility self-certification

EXHIBIT C START-UP TESTING

VISUAL AND MECHANICAL INSPECTIONS

INVERTER COMMISSIONING

ELECTRICAL OPERATION TESTS

SYSTEM MONITORING VERIFICATION

TRACKER VERIFICATION

INFRARED SCANS

BLOCK TESTING

72-HOUR FUNCTIONAL TEST

GRID MATCH TEST

POWER CHARACTERIZATION

REVENUE METER VERIFICATION

REACTIVE POWER TEST

POWER OUTPUT TEST - PLANT PERFORMANCE AND ACCEPTANCE

EXHIBIT D SCHEDULE

SCHEDULE 201 QUALIFYING FACILITY 10 MW or LESS AVOIDED COST POWER PURCHASE INFORMATION

PURPOSE

To provide information about Standard Avoided Costs and Renewable Avoided Costs, Standard Power Purchase Agreements (PPA) and Negotiated PPAs, power purchase prices and price options for power delivered by a Qualifying Facility (QF) to the Company with nameplate capacity of 10,000 kW (10MW) or less.

AVAILABLE

To owners of QFs making sales of electricity to the Company in the State of Oregon (Seller).

APPLICABLE

For power purchased from small power production or cogeneration facilities that are QFs as defined in 18 Code of Federal Regulations (CFR) Section 292, that meet the eligibility requirements described herein and where the energy is delivered to the Company's system and made available for Company purchase pursuant to a Standard PPA.

ESTABLISHING CREDITWORTHINESS

The Seller must establish creditworthiness prior to service under this schedule. For a Standard PPA, a Seller may establish creditworthiness with a written acknowledgment that it is current on all existing debt obligations and that it was not a debtor in a bankruptcy proceeding within the preceding 24 months. If the Seller is not able to establish creditworthiness, the Seller must provide security deemed sufficient by the Company as set forth in the Standard PPA.

POWER PURCHASE INFORMATION

A Seller may call the Power Production Coordinator at (503) 464-8000 to obtain more information about being a Seller or how to apply for service under this schedule.

PPA

In accordance with terms set forth in this schedule and the Commission's Rules as applicable, the Company will purchase any Energy in excess of station service (power necessary to produce generation) and amounts attributable to conversion losses, which are made available from the Seller.

A Seller must execute a PPA with the Company prior to delivery of power to the Company. The agreement will have a term of up to 20 years as selected by the QF.

A QF with a nameplate capacity rating of 10 MW or less as defined herein may elect the option of a Standard PPA.

PPA (Continued)

Any Seller may elect to negotiate a PPA with the Company. Such negotiation will comply with the requirements of the Federal Energy Regulatory Commission (FERC), and the Commission including the guidelines in Order No. 07-360, and Schedule 202. Negotiations for power purchase pricing will be based on either the filed Standard Avoided Costs or Renewable Avoided Costs in effect at that time.

STANDARD PPA (Nameplate capacity of 10 MW or less)

A Seller choosing a Standard PPA will complete all informational and price option selection requirements in the applicable Standard PPA and submit the executed Agreement to the Company prior to service under this schedule. The Standard PPA is available at www.portlandgeneral.com. The available Standard PPAs are:

- Standard In-System Non-Variable Power Purchase Agreement
- Standard Off-System Non-Variable Power Purchase Agreement
- Standard In-System Variable Power Purchase Agreement
- Standard Off-System Variable Power Purchase Agreement
- Standard Renewable In-System Non-Variable Power Purchase Agreement
- Standard Renewable Off-System Non-Variable Power Purchase Agreement
- Standard Renewable In-System Variable Power Purchase Agreement
- Standard Renewable Off-System Variable Power Purchase Agreement

The Standard PPAs applicable to variable resources are available only to QFs utilizing wind, solar or run of river hydro as the primary motive force.

GUIDELINES FOR 10 MW OR LESS FACILITIES ELECTING STANDARD PPA

To execute the Standard PPA the Seller must complete all of the general project information requested in the applicable Standard PPA.

When all information required in the Standard PPA has been received in writing from the Seller, the Company will respond within 15 business days with a draft Standard PPA.

The Seller may request in writing that the Company prepare a final draft Standard PPA. The Company will respond to this request within 15 business days. In connection with such request, the QF must provide the Company with any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft Standard PPA.

When both parties are in full agreement as to all terms and conditions of the draft Standard PPA, the Company will prepare and forward to the Seller a final executable version of the agreement within 15 business days. Following the Company's execution, an executed copy will be returned to the Seller. Prices and other terms and conditions in the PPA will not be final and binding until the Standard PPA has been executed by both parties.

OFF-SYSTEM PPA

A Seller with a facility that interconnects with an electric system other than the Company's electric system may enter into a PPA with the Company after following the applicable Standard or Negotiated PPA guidelines and making the arrangements necessary for transmission of power to the Company's system.

BASIS FOR POWER PURCHASE PRICE

AVOIDED COST SUMMARY

The power purchase prices are based on either the Company's Standard Avoided Costs or Renewable Avoided Costs in effect at the time the agreement is executed. Avoided Costs are defined in 18 CFR 292.101(6) as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."

Monthly On-Peak prices are included in both the Standard Avoided Costs as listed in Tables 1a, 2a, and 3a and Renewable Avoided Costs as listed in Tables 4a, 5a, and 6a. Monthly Off-Peak prices are included in both the Standard Avoided Costs as listed in Tables 1b, 2b, and 3b and Renewable Avoided Costs as listed in Tables 4b, 5b, and 6b.

ON-PEAK PERIOD

The On-Peak period is 6:00 a.m. until 10:00 p.m., Monday through Saturday.

OFF-PEAK PERIOD

The Off-Peak period is 10:00 p.m. until 6:00 a.m., Monday through Saturday, and all day on Sunday.

Standard Avoided Costs are based on forward market price estimates through the Resource Sufficiency Period, the period of time during which the Company's Standard Avoided Costs are associated with incremental purchases of Energy and capacity from the market. For the Resource Deficiency Period, the Standard Avoided Costs reflect the fully allocated costs of a natural gas fueled combined cycle combustion turbine (CCCT) including fuel and capital costs. The CCCT Avoided Costs are based on the variable cost of Energy plus capitalized Energy costs at a 93% capacity factor based on a natural gas price forecast, with prices modified for shrinkage and transportation costs.

Renewable Avoided Costs are based on forward market price estimates through the Renewable Resource Sufficiency Period, the period of time during which the Company's Renewable Avoided Costs are associated with incremental purchases of energy and capacity from the market. For the Renewable Resource Deficiency Period, the Renewable Avoided Costs reflect the fully allocated costs of a wind plant including capital costs.

PRICING FOR STANDARD PPA

Pricing represents the purchase price per MWh the Company will pay for electricity delivered to a Point of Delivery (POD) within the Company's service territory pursuant to a Standard PPA up to the nameplate rating of the QF in any hour. Any Energy delivered in excess of the nameplate rating will be purchased at the applicable Off-Peak Prices for the selected pricing option.

The Standard PPA pricing will be based on either the Standard or Renewable Avoided Costs in effect at the time the agreement is executed.

The Company will pay the Seller either the Off-Peak Standard Avoided Cost pursuant to Tables 1b, 2b, or 3b or the Off-Peak Renewable Avoided Costs pursuant to Tables 4b, 5b, or 6b for: (a) all Net Output delivered prior to the Commercial Operation Date; (b) all Net Output deliveries greater than Maximum Net Output in any PPA year; (c) any generation subject to and as adjusted by the provisions of Section 4.3 of the Standard PPA; (d) Net Output delivered in the Off-Peak Period; and (e) deliveries above the nameplate capacity in any hour. The Company will pay the Seller either the On-Peak Standard Avoided Cost pursuant to Tables 1a, 2a, or 3a or the On-Peak Renewable Avoided Costs pursuant to Tables 4a, 5a, or 6a for all other Net Output. (See the PPA for defined terms.)

1) Standard Fixed Price Option

The Standard Fixed Price Option is based on Standard Avoided Costs including forecasted natural gas prices. It is available to all QFs.

This option is available for a maximum term of 15 years. Prices will be as established at the time the Standard PPA is executed and will be equal to the Standard Avoided Costs in Tables 1a and 1b, 2a and 2b, or 3a and 3c, depending on the type of QF, effective at execution. QFs using any resource type other than wind and solar are assumed to be Base Load QFs.

Prices paid to the Seller under the Standard Fixed Price Option include adjustments for the capacity contribution of the QF resource type relative to that of the avoided proxy resource. Both the Base Load QF resources (Tables 1a and 1b) and the avoided proxy resource, the basis used to determine Standard Avoided Costs for the Standard Fixed Price Option, are assumed to have a capacity contribution to peak of 100%. The capacity contribution for Wind QF resources (Tables 2a and 2b) is assumed to be 5%. The capacity contribution for Solar QF resources (Tables 3a and 3b) is assumed to be 5%.

Prices paid to the Seller under the Standard Fixed Price Option for Wind QFs (Tables 2a and 2b) include a reduction for the wind integration costs in Table 7. However, if the Wind QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the wind integration charges in Table 7, in addition to the prices listed in Tables 2a and 2b, for a net-zero effect.

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

Sellers with PPAs exceeding 15 years will receive pricing equal to the Mid-C Index Price for all years up to five in excess of the initial 15.

					T.	ABLE 1a						
					Avo	ided Cos	ts					
			St	andard F	ixed Pric	e Option	for Base	Load QF	-			
				0	n-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	28.21	22.46	15.61	14.71	12.46	16.96	23.96	26.96	24.96	23.71	26.71	31.46
2017	29.96	28.21	24.71	20.96	19.46	20.46	27.96	30.96	29.46	27.71	28.71	33.71
2018	31.71	31.11	28.11	22.13	21.28	21.28	29.93	33.37	30.63	28.61	31.86	35.71
2019	33.94	31.95	27.97	23.70	22.00	23.13	31.67	35.08	33.37	31.38	32.52	38.21
2020	35.74	33.64	29.45	24.95	23.15	24.35	33.34	36.94	35.14	33.04	34.24	40.24
2021	67.43	67.34	65.41	64.69	64.41	64.50	64.61	64.73	64.84	65.48	68.60	68.72
2022	69.01	68.84	68.08	67.13	66.81	66.91	67.04	67.17	67.29	67.83	71.38	71.70
2023	71.95	71.76	70.39	69.19	69.07	69.18	69.31	69.45	69.58	70.12	73.56	73.70
2024	74.17	73.85	72.67	71.29	71.10	71.21	71.35	71.50	71.63	72.20	76.49	76.64
2025	77.19	77.30	75.84	74.88	75.02	75.14	75.30	75.47	75.62	75.80	82.57	82.89
2026	85.18	85.30	82.77	81.28	81.22	81.36	81.56	81.74	81.90	82.36	89.02	88.72
2027	86.85	86.76	85.14	83.12	82.89	83.03	83.00	83.32	83.46	83.97	91.39	91.15
2028	89.32	89.31	87.96	85.46	85.30	85.46	85.31	85.64	85.95	86.65	94.66	93.55
2029	94.06	93.99	91.23	88.74	87.97	88.15	87.71	88.06	88.61	89.34	98.37	98.11
2030	97.60	97.54	94.87	92.62	92.40	92.57	92.61	93.00	93.12	93.68	102.42	102.70
2031	99.56	99.50	96.78	94.48	94.26	94.43	94.47	94.87	94.99	95.56	104.47	104.76
2032	103.85	103.80	100.57	98.18	97.96	98.15	98.23	98.65	98.76	99.36	108.86	109.41
2033	106.56	106.51	103.17	100.72	100.50	100.69	100.78	101.21	101.32	101.93	111.67	112.26
2034	109.12	109.07	105.60	103.10	102.88	103.08	103.17	103.61	103.72	104.35	114.33	114.96
2035	111.55	111.51	107.91	105.35	105.12	105.33	105.43	105.89	105.99	106.63	116.87	117.54
2036	113.85	113.80	110.14	107.53	107.30	107.51	107.60	108.07	108.18	108.83	119.27	119.95
2037	116.50	116.45	112.72	110.06	109.82	110.04	110.14	110.61	110.73	111.39	122.03	122.73
2038	119.08	119.03	115.22	112.51	112.27	112.49	112.59	113.08	113.19	113.87	124.71	125.42
2039	121.47	121.42	117.54	114.77	114.53	114.75	114.85	115.35	115.47	116.15	127.21	127.93
2040	124.25	124.20	120.25	117.43	117.18	117.41	117.51	118.02	118.14	118.84	130.10	130.85
2041	126.72	126.67	122.64	119.76	119.51	119.74	119.85	120.36	120.49	121.20	132.68	133.44

					т.	ABLE 1b						
						ided Cost	ts					
			Sta	andard Fi		e Option		Load QF				
				0	ff-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	25.61	20.71	13.96	11.41	6.31	10.11	15.71	20.96	20.96	21.21	23.46	26.71
2017	25.71	24.21	22.21	15.71	13.71	12.71	19.71	25.21	25.46	24.71	25.71	27.96
2018	26.17	28.12	25.56	19.46	14.68	12.54	19.71	27.04	26.93	25.35	28.20	30.62
2019	29.84	28.09	25.75	18.15	15.81	14.64	22.83	29.26	29.55	28.67	29.84	32.47
2020	31.75	29.88	27.38	19.28	16.79	15.54	24.27	31.12	31.43	30.50	31.75	34.55
2021	28.88	28.79	26.86	26.15	25.87	25.95	26.07	26.19	26.30	26.94	30.06	30.18
2022	29.73	29.56	28.79	27.85	27.53	27.63	27.75	27.88	28.00	28.54	32.09	32.42
2023	31.78	31.59	30.21	29.01	28.90	29.00	29.14	29.27	29.40	29.95	33.38	33.52
2024	33.48	33.16	31.98	30.60	30.41	30.52	30.66	30.81	30.95	31.51	35.80	35.96
2025	35.58	35.69	34.24	33.27	33.42	33.53	33.70	33.86	34.01	34.19	40.97	41.28
2026	42.77	42.89	40.36	38.87	38.81	38.95	39.15	39.34	39.50	39.95	46.62	46.31
2027	43.63	43.54	41.91	39.89	39.66	39.80	39.77	40.09	40.24	40.74	48.16	47.92
2028	45.26	45.25	43.90	41.40	41.23	41.40	41.25	41.58	41.89	42.59	50.60	49.48
2029	49.15	49.08	46.32	43.83	43.06	43.24	42.80	43.15	43.70	44.43	53.46	53.20
2030	51.82	51.76	49.09	46.84	46.62	46.79	46.83	47.22	47.34	47.90	56.64	56.92
2031	52.90	52.84	50.11	47.82	47.59	47.77	47.81	48.21	48.33	48.90	57.81	58.10
2032	56.59	56.54	53.31	50.92	50.70	50.89	50.97	51.39	51.50	52.10	61.60	62.15
2033	58.08	58.03	54.69	52.24	52.02	52.21	52.30	52.73	52.84	53.45	63.19	63.78
2034	59.54	59.50	56.03	53.52	53.30	53.50	53.59	54.04	54.15	54.77	64.76	65.39
2035	61.18	61.14	57.54	54.98	54.75	54.96	55.06	55.52	55.62	56.26	66.50	67.17
2036	62.67	62.62	58.96	56.35	56.12	56.33	56.43	56.89	57.00	57.65	68.09	68.78
2037	64.17	64.12	60.39	57.73	57.49	57.71	57.80	58.28	58.39	59.06	69.69	70.39
2038	65.73	65.69	61.88	59.17	58.93	59.15	59.25	59.73	59.85	60.52	71.37	72.08
2039	67.09	67.04	63.16	60.40	60.15	60.38	60.48	60.98	61.09	61.78	72.83	73.56
2040	68.83	68.78	64.83	62.01	61.76	61.99	62.09	62.60	62.72	63.42	74.68	75.42
2041	70.23	70.17	66.14	63.27	63.02	63.25	63.36	63.87	63.99	64.71	76.19	76.95

					T	ABLE 2a						
						ided Cost	s					
				Standard	I Fixed P	rice Optic	on for Wi	nd QF				
				0	n-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	24.37	18.62	11.77	10.87	8.62	13.12	20.12	23.12	21.12	19.87	22.87	27.62
2017	26.05	24.30	20.80	17.05	15.55	16.55	24.05	27.05	25.55	23.80	24.80	29.80
2018	27.72	27.12	24.12	18.14	17.29	17.29	25.94	29.38	26.64	24.62	27.87	31.72
2019	29.87	27.88	23.90	19.63	17.93	19.06	27.60	31.01	29.30	27.31	28.45	34.14
2020	31.59	29.49	25.30	20.80	19.00	20.20	29.19	32.79	30.99	28.89	30.09	36.09
2021	30.68	30.59	28.66	27.94	27.66	27.75	27.87	27.99	28.10	28.74	31.86	31.98
2022	31.56	31.39	30.62	29.68	29.36	29.46	29.59	29.72	29.84	30.38	33.93	34.25
2023	33.67	33.48	32.11	30.91	30.79	30.90	31.03	31.17	31.30	31.84	35.28	35.42
2024	35.38	35.06	33.88	32.49	32.30	32.42	32.56	32.70	32.84	33.40	37.70	37.85
2025	37.53	37.64	36.18	35.22	35.36	35.48	35.64	35.81	35.96	36.14	42.91	43.23
2026	44.75	44.87	42.35	40.86	40.79	40.94	41.13	41.32	41.48	41.94	48.60	48.29
2027	45.65	45.56	43.93	41.91	41.68	41.82	41.79	42.12	42.26	42.76	50.18	49.94
2028	47.32	47.31	45.96	43.46	43.30	43.46	43.31	43.64	43.95	44.65	52.66	51.55
2029	51.25	51.18	48.43	45.94	45.16	45.34	44.90	45.25	45.80	46.53	55.57	55.30
2030	53.96	53.90	51.23	48.98	48.76	48.93	48.97	49.36	49.48	50.04	58.78	59.06
2031	55.08	55.02	52.29	50.00	49.77	49.95	49.99	50.38	50.51	51.08	59.99	60.28
2032	58.77	58.72	55.49	53.10	52.88	53.07	53.15	53.57	53.68	54.28	63.78	64.33
2033	60.35	60.30	56.96	54.51	54.29	54.49	54.57	55.00	55.11	55.72	65.46	66.05
2034	61.88	61.83	58.36	55.86	55.63	55.84	55.93	56.37	56.48	57.10	67.09	67.72
2035	63.54	63.49	59.90	57.34	57.11	57.32	57.42	57.87	57.98	58.62	68.86	69.53
2036	65.04	65.00	61.33	58.72	58.49	58.70	58.80	59.27	59.38	60.03	70.46	71.15
2037	66.61	66.57	62.83	60.17	59.93	60.15	60.25	60.73	60.84	61.50	72.14	72.84
2038	68.23	68.18	64.37	61.66	61.42	61.64	61.74	62.23	62.34	63.02	73.86	74.57
2039	69.64	69.59	65.71	62.94	62.70	62.92	63.03	63.52	63.64	64.33	75.38	76.11
2040	71.42	71.37	67.41	64.60	64.35	64.58	64.68	65.18	65.30	66.00	77.27	78.01
2041	72.87	72.82	68.79	65.92	65.66	65.90	66.00	66.52	66.64	67.35	78.84	79.59

					TA	ABLE 2b						
					Avoi	ded Cost	s					
				Standard	I Fixed P	rice Optic	on for Wi	nd QF				
				0	ff-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	21.77	16.87	10.12	7.57	2.47	6.27	11.87	17.12	17.12	17.37	19.62	22.87
2017	21.80	20.30	18.30	11.80	9.80	8.80	15.80	21.30	21.55	20.80	21.80	24.05
2018	22.18	24.13	21.57	15.47	10.69	8.55	15.72	23.05	22.94	21.36	24.21	26.63
2019	25.77	24.02	21.68	14.08	11.74	10.57	18.76	25.19	25.48	24.60	25.77	28.40
2020	27.60	25.73	23.23	15.13	12.64	11.39	20.12	26.97	27.28	26.35	27.60	30.40
2021	24.65	24.56	22.63	21.92	21.64	21.72	21.84	21.96	22.07	22.71	25.83	25.95
2022	25.42	25.25	24.48	23.54	23.22	23.32	23.44	23.57	23.69	24.23	27.78	28.11
2023	27.39	27.20	25.82	24.62	24.51	24.61	24.75	24.88	25.01	25.56	28.99	29.13
2024	29.01	28.69	27.51	26.13	25.94	26.05	26.19	26.34	26.48	27.04	31.33	31.49
2025	31.02	31.13	29.68	28.71	28.86	28.97	29.14	29.30	29.45	29.63	36.41	36.72
2026	38.12	38.24	35.71	34.22	34.16	34.30	34.50	34.69	34.85	35.30	41.97	41.66
2027	38.89	38.80	37.17	35.15	34.92	35.06	35.03	35.35	35.50	36.00	43.42	43.18
2028	40.43	40.42	39.07	36.57	36.40	36.57	36.42	36.75	37.06	37.76	45.77	44.65
2029	44.23	44.16	41.40	38.91	38.14	38.32	37.88	38.23	38.78	39.51	48.54	48.28
2030	46.80	46.74	44.07	41.82	41.60	41.77	41.81	42.20	42.32	42.88	51.62	51.90
2031	47.78	47.72	44.99	42.70	42.47	42.65	42.69	43.09	43.21	43.78	52.69	52.98
2032	51.38	51.33	48.10	45.71	45.49	45.68	45.76	46.18	46.29	46.89	56.39	56.94
2033	52.77	52.72	49.38	46.93	46.71	46.90	46.99	47.42	47.53	48.14	57.88	58.47
2034	54.12	54.08	50.61	48.10	47.88	48.08	48.17	48.62	48.73	49.35	59.34	59.97
2035	55.66	55.62	52.02	49.46	49.23	49.44	49.54	50.00	50.10	50.74	60.98	61.65
2036	57.04	56.99	53.33	50.72	50.49	50.70	50.80	51.26	51.37	52.02	62.46	63.15
2037	58.43	58.38	54.65	51.99	51.75	51.97	52.06	52.54	52.65	53.32	63.95	64.65
2038	59.88	59.84	56.03	53.32	53.08	53.30	53.40	53.88	54.00	54.67	65.52	66.23
2039	61.13	61.08	57.20	54.44	54.19	54.42	54.52	55.02	55.13	55.82	66.87	67.60
2040	62.75	62.70	58.75	55.93	55.68	55.91	56.01	56.52	56.64	57.34	68.60	69.34
2041	64.04	63.98	59.95	57.08	56.83	57.06	57.17	57.68	57.80	58.52	70.00	70.76

					T	ABLE 3a						
					Avoi	ded Cos	ts					
				Standard	I Fixed P	rice Optic	on for So	lar QF				
				0	n-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	28.21	22.46	15.61	14.71	12.46	16.96	23.96	26.96	24.96	23.71	26.71	31.46
2017	29.96	28.21	24.71	20.96	19.46	20.46	27.96	30.96	29.46	27.71	28.71	33.71
2018	31.71	31.11	28.11	22.13	21.28	21.28	29.93	33.37	30.63	28.61	31.86	35.71
2019	33.94	31.95	27.97	23.70	22.00	23.13	31.67	35.08	33.37	31.38	32.52	38.21
2020	35.74	33.64	29.45	24.95	23.15	24.35	33.34	36.94	35.14	33.04	34.24	40.24
2021	33.98	33.89	31.96	31.24	30.96	31.05	31.16	31.28	31.39	32.03	35.15	35.27
2022	34.92	34.75	33.98	33.04	32.72	32.82	32.94	33.08	33.20	33.74	37.28	37.61
2023	37.09	36.90	35.52	34.32	34.21	34.31	34.44	34.58	34.71	35.26	38.69	38.83
2024	38.86	38.54	37.36	35.98	35.79	35.90	36.04	36.19	36.32	36.88	41.18	41.33
2025	41.08	41.19	39.73	38.77	38.92	39.03	39.19	39.36	39.51	39.69	46.46	46.78
2026	48.37	48.49	45.97	44.48	44.42	44.56	44.75	44.94	45.10	45.56	52.22	51.91
2027	49.34	49.25	47.62	45.61	45.38	45.51	45.48	45.81	45.95	46.45	53.87	53.63
2028	51.08	51.07	49.72	47.22	47.06	47.22	47.07	47.40	47.72	48.41	56.42	55.31
2029	55.08	55.01	52.26	49.77	48.99	49.17	48.73	49.08	49.63	50.36	59.40	59.13
2030	57.87	57.81	55.14	52.89	52.67	52.84	52.88	53.27	53.39	53.95	62.69	62.97
2031	59.07	59.00	56.28	53.98	53.76	53.93	53.98	54.37	54.49	55.06	63.98	64.26
2032	62.83	62.78	59.56	57.16	56.94	57.13	57.21	57.64	57.75	58.34	67.85	68.39
2033	64.49	64.44	61.09	58.64	58.42	58.62	58.70	59.14	59.25	59.86	69.60	70.18
2034	66.10	66.05	62.58	60.08	59.85	60.05	60.14	60.59	60.70	61.32	71.31	71.94
2035	67.84	67.79	64.20	61.64	61.41	61.62	61.71	62.17	62.28	62.92	73.16	73.83
2036	69.43	69.38	65.72	63.11	62.88	63.09	63.19	63.66	63.77	64.42	74.85	75.54
2037	71.08	71.04	67.30	64.64	64.40	64.62	64.72	65.20	65.31	65.97	76.61	77.31
2038	72.78	72.73	68.93	66.22	65.98	66.20	66.30	66.78	66.90	67.57	78.42	79.13
2039	74.28	74.23	70.35	67.58	67.34	67.56	67.67	68.16	68.28	68.97	80.02	80.75
2040	76.15	76.10	72.15	69.33	69.08	69.31	69.42	69.92	70.04	70.74	82.01	82.75
2041	77.69	77.64	73.61	70.74	70.48	70.72	70.82	71.34	71.46	72.17	83.66	84.41

					T	ABLE 3b						
					Avoi	ded Cos	ts					
				Standard	I Fixed P	rice Optic	on for So	lar QF				
				0	ff-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	25.61	20.71	13.96	11.41	6.31	10.11	15.71	20.96	20.96	21.21	23.46	26.71
2017	25.71	24.21	22.21	15.71	13.71	12.71	19.71	25.21	25.46	24.71	25.71	27.96
2018	26.17	28.12	25.56	19.46	14.68	12.54	19.71	27.04	26.93	25.35	28.20	30.62
2019	29.84	28.09	25.75	18.15	15.81	14.64	22.83	29.26	29.55	28.67	29.84	32.47
2020	31.75	29.88	27.38	19.28	16.79	15.54	24.27	31.12	31.43	30.50	31.75	34.55
2021	28.88	28.79	26.86	26.15	25.87	25.95	26.07	26.19	26.30	26.94	30.06	30.18
2022	29.73	29.56	28.79	27.85	27.53	27.63	27.75	27.88	28.00	28.54	32.09	32.42
2023	31.78	31.59	30.21	29.01	28.90	29.00	29.14	29.27	29.40	29.95	33.38	33.52
2024	33.48	33.16	31.98	30.60	30.41	30.52	30.66	30.81	30.95	31.51	35.80	35.96
2025	35.58	35.69	34.24	33.27	33.42	33.53	33.70	33.86	34.01	34.19	40.97	41.28
2026	42.77	42.89	40.36	38.87	38.81	38.95	39.15	39.34	39.50	39.95	46.62	46.31
2027	43.63	43.54	41.91	39.89	39.66	39.80	39.77	40.09	40.24	40.74	48.16	47.92
2028	45.26	45.25	43.90	41.40	41.23	41.40	41.25	41.58	41.89	42.59	50.60	49.48
2029	49.15	49.08	46.32	43.83	43.06	43.24	42.80	43.15	43.70	44.43	53.46	53.20
2030	51.82	51.76	49.09	46.84	46.62	46.79	46.83	47.22	47.34	47.90	56.64	56.92
2031	52.90	52.84	50.11	47.82	47.59	47.77	47.81	48.21	48.33	48.90	57.81	58.10
2032	56.59	56.54	53.31	50.92	50.70	50.89	50.97	51.39	51.50	52.10	61.60	62.15
2033	58.08	58.03	54.69	52.24	52.02	52.21	52.30	52.73	52.84	53.45	63.19	63.78
2034	59.54	59.50	56.03	53.52	53.30	53.50	53.59	54.04	54.15	54.77	64.76	65.39
2035	61.18	61.14	57.54	54.98	54.75	54.96	55.06	55.52	55.62	56.26	66.50	67.17
2036	62.67	62.62	58.96	56.35	56.12	56.33	56.43	56.89	57.00	57.65	68.09	68.78
2037	64.17	64.12	60.39	57.73	57.49	57.71	57.80	58.28	58.39	59.06	69.69	70.39
2038	65.73	65.69	61.88	59.17	58.93	59.15	59.25	59.73	59.85	60.52	71.37	72.08
2039	67.09	67.04	63.16	60.40	60.15	60.38	60.48	60.98	61.09	61.78	72.83	73.56
2040	68.83	68.78	64.83	62.01	61.76	61.99	62.09	62.60	62.72	63.42	74.68	75.42
2041	70.23	70.17	66.14	63.27	63.02	63.25	63.36	63.87	63.99	64.71	76.19	76.95

PRICING OPTIONS FOR STANDARD PPA (Continued)

2) Renewable Fixed Price Option

The Renewable Fixed Price Option is based on Renewable Avoided Costs. It is available only to Renewable QFs that generate electricity from a renewable energy source that may be used by the Company to comply with the Oregon Renewable Portfolio Standard as set forth in ORS 469A.005 to 469A.210.

This option is available for a maximum term of 15 years. Prices will be as established at the time the Standard PPA is executed and will be equal to the Renewable Avoided Costs in Tables 4a and 4b, 5a and 5b, or 6a and 6b, depending on the type of QF, effective at execution. QFs using any resource type other than wind and solar are assumed to be Base Load QFs.

Sellers will retain all Environmental Attributes generated by the facility during the Renewable Resource Sufficiency Period. A Renewable QF choosing the Renewable Fixed Price Option must cede all RPS Attributes generated by the facility to the Company from the start of the Renewable Resource Deficiency Period through the remainder of the PPA term.

Prices paid to the Seller under the Renewable Fixed Price Option include adjustments for the capacity contribution of the QF resource type relative to that of the avoided proxy resource. Both Wind QF resources (Tables 5a and 5b) and the avoided proxy resource, the basis used to determine Renewable Avoided Costs for the Renewable Fixed Price Option, are assumed to have a capacity contribution to peak of 5%. The capacity contribution for Solar QF resources (Tables 6a and 6b) is assumed to be 5%. The capacity contribution for Base Load QF resources (Tables 4a and 4b) is assumed to be 100%.

The Renewable Avoided Costs during the Renewable Resource Deficiency Period reflect an increase for avoided wind integration costs, shown in Table 7.

Prices paid to the Seller under the Renewable Fixed Price Option for Wind QFs (Tables 5a and 5b) include a reduction for the wind integration costs in Table 7, which cancels out wind integration costs included in the Renewable Avoided Costs during the Renewable Resource Deficiency Period. However, if the Wind QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the wind integration charges in Table 7, in addition to the prices listed in Tables 5a and 5b.

Sellers with PPAs exceeding 15 years will receive pricing equal to the Mid-C Index Price for all years up to five in excess of the initial 15.

					T.	ABLE 4a						
				F	Renewabl	e Avoide	d Costs					
			Rer	newable l	Fixed Price	ce Option	for Base	e Load Q	F			
				0	n-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	28.36	22.61	15.76	14.86	12.61	17.11	24.11	27.11	25.11	23.86	26.86	31.61
2017	30.11	28.36	24.86	21.11	19.61	20.61	28.11	31.11	29.61	27.86	28.86	33.86
2018	31.86	31.26	28.26	22.28	21.43	21.43	30.08	33.52	30.78	28.76	32.01	35.86
2019	34.10	32.11	28.13	23.86	22.16	23.29	31.83	35.24	33.53	31.54	32.68	38.37
2020	115.34	115.32	114.56	115.02	118.22	117.33	117.01	116.89	115.60	114.63	115.47	114.45
2021	117.94	118.18	116.67	117.75	120.59	119.83	119.26	119.77	118.26	117.25	118.55	117.22
2022	120.48	120.36	118.46	120.19	123.17	122.14	121.69	121.65	120.55	119.55	120.98	119.53
2023	123.26	122.83	120.85	122.92	125.37	124.64	124.29	123.92	123.08	121.92	123.63	122.53
2024	124.86	125.01	123.06	125.07	127.80	126.78	126.67	126.41	126.22	123.83	124.83	124.96
2025	127.73	128.05	125.86	128.21	131.66	130.48	129.53	129.66	128.84	126.59	127.76	127.41
2026	130.91	130.58	129.12	131.30	135.76	132.28	132.28	132.69	132.40	129.34	131.17	130.23
2027	133.47	133.03	131.38	133.50	139.48	134.88	134.51	135.95	134.79	131.96	133.26	132.78
2028	135.95	134.91	132.89	136.24	141.79	136.93	137.64	137.65	136.77	134.76	135.84	135.06
2029	138.81	138.57	135.91	139.29	149.30	140.74	140.82	140.82	140.86	137.50	138.32	138.21
2030	141.68	141.39	139.11	142.00	153.18	145.20	143.05	142.93	144.31	140.18	140.75	140.79
2031	144.29	143.79	142.17	145.52	156.10	149.27	145.71	146.65	146.86	143.04	144.15	143.71
2032	146.51	146.00	144.35	147.76	158.51	151.58	147.95	148.91	149.13	145.24	146.37	145.92
2033	149.91	149.40	147.71	151.19	162.18	155.09	151.39	152.37	152.59	148.62	149.77	149.31
2034	152.96	152.43	150.71	154.26	165.46	158.24	154.46	155.46	155.68	151.64	152.81	152.35
2035	155.76	155.22	153.46	157.08	168.50	161.14	157.29	158.31	158.54	154.41	155.60	155.13
2036	158.31	157.76	155.97	159.65	171.26	163.78	159.86	160.90	161.13	156.94	158.15	157.67
2037	161.83	161.27	159.44	163.20	175.07	167.42	163.42	164.48	164.71	160.43	161.67	161.18
2038	164.95	164.38	162.52	166.35	178.45	170.65	166.57	167.65	167.89	163.52	164.79	164.29
2039	168.13	167.55	165.66	169.56	181.89	173.94	169.79	170.89	171.13	166.68	167.97	167.46
2040	171.05	170.46	168.54	172.51	185.04	176.96	172.74	173.85	174.10	169.58	170.89	170.37
2041	174.69	174.08	172.11	176.17	188.98	180.72	176.40	177.55	177.80	173.18	174.52	173.99

					T	ABLE 4b						
				R	enewable	e Avoide	d Costs					
			Rer	newable F	ixed Pric	e Option	for Base	Load QI	F			
				0	ff-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	25.76	20.86	14.11	11.56	6.46	10.26	15.86	21.11	21.11	21.36	23.61	26.86
2017	25.86	24.36	22.36	15.86	13.86	12.86	19.86	25.36	25.61	24.86	25.86	28.11
2018	26.32	28.27	25.71	19.61	14.83	12.69	19.86	27.19	27.08	25.50	28.35	30.77
2019	30.00	28.25	25.91	18.31	15.97	14.80	22.99	29.42	29.71	28.83	30.00	32.63
2020	62.76	63.02	64.56	63.31	59.92	60.16	60.45	61.61	62.52	63.74	63.55	63.99
2021	64.93	64.15	65.85	64.48	61.58	61.62	62.27	62.62	63.78	65.82	63.38	65.09
2022	65.85	65.52	67.77	65.49	62.45	62.82	64.33	63.35	65.00	67.04	64.42	66.29
2023	66.70	66.75	69.10	67.28	62.84	64.01	65.40	64.85	66.14	68.41	65.38	67.63
2024	67.25	67.31	70.47	67.09	63.18	65.92	64.75	65.12	66.62	68.68	67.42	68.05
2025	68.62	68.60	71.94	68.08	63.17	66.28	66.12	67.12	67.23	70.19	69.68	69.06
2026	68.95	69.85	72.28	68.56	63.85	67.22	67.05	67.75	67.05	71.12	69.85	69.89
2027	71.31	71.29	73.13	70.34	63.69	68.45	68.79	68.16	68.57	73.22	70.67	71.18
2028	72.28	72.90	75.41	72.10	63.09	69.98	70.15	68.82	70.20	73.79	71.48	73.41
2029	72.78	73.60	76.79	73.50	58.25	70.29	71.37	70.00	71.53	74.58	73.61	74.68
2030	73.91	74.82	78.36	73.64	58.00	70.89	72.02	72.19	72.00	75.99	75.36	76.23
2031	75.51	76.70	79.40	74.00	59.17	70.67	73.55	73.71	72.16	77.24	77.07	76.31
2032	76.76	77.97	80.71	75.23	60.15	71.83	74.76	74.93	73.35	78.52	78.34	77.57
2033	78.46	79.69	82.50	76.89	61.48	73.42	76.42	76.58	74.97	80.25	80.07	79.29
2034	79.97	81.23	84.09	78.37	62.66	74.84	77.89	78.06	76.42	81.80	81.62	80.82
2035	81.52	82.80	85.71	79.88	63.87	76.28	79.39	79.57	77.89	83.38	83.19	82.38
2036	82.86	84.17	87.13	81.20	64.93	77.54	80.70	80.88	79.18	84.76	84.57	83.74
2037	84.69	86.03	89.05	83.00	66.36	79.25	82.49	82.67	80.93	86.63	86.44	85.59
2038	86.33	87.69	90.77	84.60	67.64	80.78	84.08	84.26	82.49	88.30	88.11	87.24
2039	87.99	89.38	92.52	86.23	68.95	82.34	85.70	85.89	84.08	90.01	89.81	88.92
2040	89.45	90.85	94.05	87.66	70.09	83.70	87.12	87.31	85.47	91.49	91.29	90.39
2041	91.42	92.86	96.13	89.59	71.63	85.55	89.04	89.24	87.36	93.51	93.31	92.39

					T.	ABLE 5a						
				F	Renewabl	e Avoide	d Costs					
			F	Renewab	le Fixed F	Price Opt	ion for W	ind QF				
				0	n-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	24.52	18.77	11.92	11.02	8.77	13.27	20.27	23.27	21.27	20.02	23.02	27.77
2017	26.20	24.45	20.95	17.20	15.70	16.70	24.20	27.20	25.70	23.95	24.95	29.95
2018	27.87	27.27	24.27	18.29	17.44	17.44	26.09	29.53	26.79	24.77	28.02	31.87
2019	30.03	28.04	24.06	19.79	18.09	19.22	27.76	31.17	29.46	27.47	28.61	34.30
2020	75.38	75.37	74.61	75.06	78.26	77.37	77.05	76.93	75.64	74.67	75.51	74.49
2021	77.10	77.33	75.83	76.90	79.75	78.99	78.41	78.92	77.41	76.40	77.70	76.38
2022	78.85	78.72	76.82	78.56	81.53	80.51	80.05	80.02	78.92	77.92	79.34	77.90
2023	80.71	80.27	78.29	80.37	82.82	82.08	81.73	81.37	80.53	79.36	81.08	79.97
2024	81.74	81.89	79.93	81.95	84.68	83.66	83.55	83.28	83.10	80.71	81.71	81.84
2025	83.64	83.97	81.78	84.13	87.57	86.40	85.44	85.57	84.75	82.51	83.68	83.32
2026	85.97	85.64	84.18	86.37	90.82	87.34	87.34	87.75	87.46	84.40	86.23	85.29
2027	87.67	87.23	85.57	87.69	93.67	89.07	88.71	90.15	88.99	86.16	87.45	86.98
2028	89.26	88.22	86.20	89.55	95.10	90.24	90.95	90.96	90.08	88.07	89.15	88.37
2029	91.22	90.98	88.32	91.70	101.72	93.16	93.23	93.23	93.28	89.92	90.73	90.62
2030	93.17	92.88	90.60	93.49	104.67	96.69	94.54	94.42	95.80	91.67	92.24	92.28
2031	94.84	94.34	92.72	96.07	106.65	99.82	96.26	97.20	97.42	93.59	94.70	94.26
2032	96.40	95.90	94.24	97.65	108.40	101.47	97.85	98.80	99.02	95.13	96.26	95.82
2033	98.55	98.03	96.34	99.82	110.81	103.72	100.02	101.00	101.22	97.25	98.40	97.95
2034	100.44	99.91	98.19	101.74	112.94	105.72	101.94	102.94	103.17	99.12	100.29	99.83
2035	102.38	101.85	100.09	103.71	115.13	107.76	103.92	104.93	105.16	101.04	102.23	101.76
2036	104.06	103.51	101.72	105.40	117.01	109.53	105.61	106.65	106.88	102.69	103.90	103.42
2037	106.37	105.81	103.99	107.74	119.61	111.96	107.96	109.02	109.26	104.97	106.21	105.72
2038	108.42	107.86	105.99	109.82	121.92	114.12	110.05	111.12	111.37	107.00	108.26	107.76
2039	110.52	109.94	108.04	111.95	124.27	116.33	112.17	113.27	113.52	109.07	110.36	109.85
2040	112.32	111.73	109.81	113.77	126.31	118.23	114.00	115.12	115.37	110.85	112.16	111.64
2041	114.83	114.23	112.26	116.31	129.12	120.86	116.55	117.69	117.95	113.32	114.66	114.13

					T	ABLE 5b						
				R	enewabl	e Avoide	d Costs					
			F	Renewabl	e Fixed F	Price Opt	ion for W	ind QF				
				0	ff-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	21.92	17.02	10.27	7.72	2.62	6.42	12.02	17.27	17.27	17.52	19.77	23.02
2017	21.95	20.45	18.45	11.95	9.95	8.95	15.95	21.45	21.70	20.95	21.95	24.20
2018	22.33	24.28	21.72	15.62	10.84	8.70	15.87	23.20	23.09	21.51	24.36	26.78
2019	25.93	24.18	21.84	14.24	11.90	10.73	18.92	25.35	25.64	24.76	25.93	28.56
2020	58.61	58.87	60.41	59.16	55.77	56.01	56.30	57.46	58.37	59.59	59.40	59.84
2021	60.70	59.92	61.62	60.25	57.35	57.39	58.04	58.39	59.55	61.59	59.15	60.86
2022	61.54	61.21	63.46	61.18	58.14	58.51	60.02	59.04	60.69	62.73	60.11	61.98
2023	62.31	62.36	64.71	62.89	58.45	59.62	61.01	60.46	61.75	64.02	60.99	63.24
2024	62.78	62.84	66.00	62.62	58.71	61.45	60.28	60.65	62.15	64.21	62.95	63.58
2025	64.06	64.04	67.38	63.52	58.61	61.72	61.56	62.56	62.67	65.63	65.12	64.50
2026	64.30	65.20	67.63	63.91	59.20	62.57	62.40	63.10	62.40	66.47	65.20	65.24
2027	66.57	66.55	68.39	65.60	58.95	63.71	64.05	63.42	63.83	68.48	65.93	66.44
2028	67.45	68.07	70.58	67.27	58.26	65.15	65.32	63.99	65.37	68.96	66.65	68.58
2029	67.86	68.68	71.87	68.58	53.33	65.37	66.45	65.08	66.61	69.66	68.69	69.76
2030	68.89	69.80	73.34	68.62	52.98	65.87	67.00	67.17	66.98	70.97	70.34	71.21
2031	70.39	71.58	74.28	68.88	54.05	65.55	68.43	68.59	67.04	72.12	71.95	71.19
2032	71.55	72.76	75.50	70.02	54.94	66.62	69.55	69.72	68.14	73.31	73.13	72.36
2033	73.15	74.38	77.19	71.58	56.17	68.11	71.11	71.27	69.66	74.94	74.76	73.98
2034	74.55	75.81	78.67	72.95	57.24	69.42	72.47	72.64	71.00	76.38	76.20	75.40
2035	76.00	77.28	80.19	74.36	58.35	70.76	73.87	74.05	72.37	77.86	77.67	76.86
2036	77.23	78.54	81.50	75.57	59.30	71.91	75.07	75.25	73.55	79.13	78.94	78.11
2037	78.95	80.29	83.31	77.26	60.62	73.51	76.75	76.93	75.19	80.89	80.70	79.85
2038	80.48	81.84	84.92	78.75	61.79	74.93	78.23	78.41	76.64	82.45	82.26	81.39
2039	82.03	83.42	86.56	80.27	62.99	76.38	79.74	79.93	78.12	84.05	83.85	82.96
2040	83.37	84.77	87.97	81.58	64.01	77.62	81.04	81.23	79.39	85.41	85.21	84.31
2041	85.23	86.67	89.94	83.40	65.44	79.36	82.85	83.05	81.17	87.32	87.12	86.20

PRICING OPTIONS FOR STANDARD PPA (Continued) Renewable Fixed Price Option (Continued)

					T.	ABLE 6a						
				F	Renewabl	e Avoide	d Costs					
				Renewab	le Fixed F	Price Opt	ion for S	olar QF				
				0	n-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	28.36	22.61	15.76	14.86	12.61	17.11	24.11	27.11	25.11	23.86	26.86	31.61
2017	30.11	28.36	24.86	21.11	19.61	20.61	28.11	31.11	29.61	27.86	28.86	33.86
2018	31.86	31.26	28.26	22.28	21.43	21.43	30.08	33.52	30.78	28.76	32.01	35.86
2019	34.10	32.11	28.13	23.86	22.16	23.29	31.83	35.24	33.53	31.54	32.68	38.37
2020	78.62	78.60	77.84	78.30	81.50	80.60	80.29	80.17	78.88	77.91	78.74	77.73
2021	80.39	80.63	79.12	80.20	83.04	82.28	81.71	82.22	80.71	79.70	81.00	79.67
2022	82.21	82.08	80.18	81.92	84.89	83.87	83.41	83.38	82.27	81.27	82.70	81.25
2023	84.12	83.69	81.71	83.78	86.23	85.50	85.15	84.78	83.94	82.78	84.50	83.39
2024	85.22	85.37	83.41	85.43	88.16	87.14	87.03	86.76	86.58	84.19	85.19	85.32
2025	87.19	87.52	85.33	87.68	91.12	89.95	88.99	89.12	88.30	86.06	87.23	86.87
2026	89.59	89.26	87.80	89.99	94.44	90.96	90.96	91.37	91.08	88.02	89.85	88.91
2027	91.36	90.92	89.26	91.39	97.36	92.76	92.40	93.84	92.68	89.85	91.14	90.67
2028	93.02	91.98	89.96	93.31	98.86	94.00	94.71	94.72	93.84	91.84	92.91	92.13
2029	95.05	94.81	92.15	95.53	105.55	96.99	97.06	97.06	97.11	93.75	94.56	94.45
2030	97.08	96.79	94.51	97.40	108.58	100.60	98.45	98.33	99.71	95.58	96.15	96.19
2031	98.83	98.33	96.70	100.05	110.63	103.81	100.25	101.19	101.40	97.58	98.69	98.25
2032	100.47	99.96	98.30	101.71	112.47	105.53	101.91	102.87	103.08	99.20	100.32	99.88
2033	102.68	102.16	100.47	103.95	114.95	107.86	104.16	105.14	105.36	101.38	102.53	102.08
2034	104.66	104.13	102.41	105.96	117.16	109.94	106.16	107.16	107.38	103.34	104.51	104.05
2035	106.68	106.15	104.39	108.01	119.43	112.06	108.21	109.23	109.46	105.34	106.53	106.06
2036	108.44	107.90	106.11	109.79	121.40	113.91	110.00	111.04	111.27	107.08	108.29	107.81
2037	110.84	110.28	108.46	112.21	124.08	116.43	112.43	113.49	113.73	109.44	110.68	110.19
2038	112.98	112.41	110.55	114.38	126.47	118.68	114.60	115.68	115.92	111.55	112.82	112.32
2039	115.16	114.58	112.68	116.59	128.92	120.97	116.81	117.91	118.16	113.71	115.00	114.49
2040	117.06	116.47	114.54	118.51	131.04	122.96	118.74	119.86	120.11	115.58	116.89	116.37
2041	119.65	119.05	117.07	121.13	133.94	125.68	121.37	122.51	122.76	118.14	119.48	118.95

PRICING OPTIONS FOR STANDARD PPA (Continued) Renewable Fixed Price Option (Continued)

					TA	ABLE 6b						
				R	enewable	e Avoide	d Costs					
			F	Renewabl	e Fixed F	Price Opt	ion for So	olar QF				
				0	ff-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	25.76	20.86	14.11	11.56	6.46	10.26	15.86	21.11	21.11	21.36	23.61	26.86
2017	25.86	24.36	22.36	15.86	13.86	12.86	19.86	25.36	25.61	24.86	25.86	28.11
2018	26.32	28.27	25.71	19.61	14.83	12.69	19.86	27.19	27.08	25.50	28.35	30.77
2019	30.00	28.25	25.91	18.31	15.97	14.80	22.99	29.42	29.71	28.83	30.00	32.63
2020	62.76	63.02	64.56	63.31	59.92	60.16	60.45	61.61	62.52	63.74	63.55	63.99
2021	64.93	64.15	65.85	64.48	61.58	61.62	62.27	62.62	63.78	65.82	63.38	65.09
2022	65.85	65.52	67.77	65.49	62.45	62.82	64.33	63.35	65.00	67.04	64.42	66.29
2023	66.70	66.75	69.10	67.28	62.84	64.01	65.40	64.85	66.14	68.41	65.38	67.63
2024	67.25	67.31	70.47	67.09	63.18	65.92	64.75	65.12	66.62	68.68	67.42	68.05
2025	68.62	68.60	71.94	68.08	63.17	66.28	66.12	67.12	67.23	70.19	69.68	69.06
2026	68.95	69.85	72.28	68.56	63.85	67.22	67.05	67.75	67.05	71.12	69.85	69.89
2027	71.31	71.29	73.13	70.34	63.69	68.45	68.79	68.16	68.57	73.22	70.67	71.18
2028	72.28	72.90	75.41	72.10	63.09	69.98	70.15	68.82	70.20	73.79	71.48	73.41
2029	72.78	73.60	76.79	73.50	58.25	70.29	71.37	70.00	71.53	74.58	73.61	74.68
2030	73.91	74.82	78.36	73.64	58.00	70.89	72.02	72.19	72.00	75.99	75.36	76.23
2031	75.51	76.70	79.40	74.00	59.17	70.67	73.55	73.71	72.16	77.24	77.07	76.31
2032	76.76	77.97	80.71	75.23	60.15	71.83	74.76	74.93	73.35	78.52	78.34	77.57
2033	78.46	79.69	82.50	76.89	61.48	73.42	76.42	76.58	74.97	80.25	80.07	79.29
2034	79.97	81.23	84.09	78.37	62.66	74.84	77.89	78.06	76.42	81.80	81.62	80.82
2035	81.52	82.80	85.71	79.88	63.87	76.28	79.39	79.57	77.89	83.38	83.19	82.38
2036	82.86	84.17	87.13	81.20	64.93	77.54	80.70	80.88	79.18	84.76	84.57	83.74
2037	84.69	86.03	89.05	83.00	66.36	79.25	82.49	82.67	80.93	86.63	86.44	85.59
2038	86.33	87.69	90.77	84.60	67.64	80.78	84.08	84.26	82.49	88.30	88.11	87.24
2039	87.99	89.38	92.52	86.23	68.95	82.34	85.70	85.89	84.08	90.01	89.81	88.92
2040	89.45	90.85	94.05	87.66	70.09	83.70	87.12	87.31	85.47	91.49	91.29	90.39
2041	91.42	92.86	96.13	89.59	71.63	85.55	89.04	89.24	87.36	93.51	93.31	92.39

WIND INTEGRATION

TAE	BLE 7
Wind In	tegration
Year	Cost
2015	3.77
2016	3.84
2017	3.91
2018	3.99
2019	4.07
2020	4.15
2021	4.23
2022	4.31
2023	4.39
2024	4.47
2025	4.56
2026	4.65
2027	4.74
2028	4.83
2029	4.92
2030	5.02
2031	5.12
2032	5.21
2033	5.31
2034	5.42
2035	5.52
2036	5.63
2037	5.74
2038	5.85
2039	5.96
2040	6.08

MONTHLY SERVICE CHARGE

Each separately metered QF not associated with a retail Customer account will be charged \$10.00 per month.

INSURANCE REQUIREMENTS

The following insurance requirements are applicable to Sellers with a Standard PPA:

- 1) QFs with nameplate capacity ratings greater than 200 kW are required to secure and maintain a prudent amount of general liability insurance. The Seller must certify to the Company that it is maintaining general liability insurance coverage for each QF at prudent amounts. A prudent amount will be deemed to mean liability insurance coverage for both bodily injury and property damage liability in the amount of not less than \$1,000,000 each occurrence combined single limit, which limits may be required to be increased or decreased by the Company as the Company determines in its reasonable judgment, that economic conditions or claims experience may warrant.
- Such insurance will include an endorsement naming the Company as an additional insured insofar as liability arising out of operations under this schedule and a provision that such liability policies will not be canceled or their limits reduced without 30 days' written notice to the Company. The Seller will furnish the Company with certificates of insurance together with the endorsements required herein. The Company will have the right to inspect the original policies of such insurance.
- 3) QFs with a design capacity of 200 kW or less are encouraged to pursue liability insurance on their own. The Oregon Public Utility Commission in Order No. 05-584 determined that it is inappropriate to require QFs that have a design capacity of 200 kW or less to obtain general liability insurance.

TRANSMISSION AGREEMENTS

If the QF is located outside the Company's service territory, the Seller is responsible for the transmission of power at its cost to the Company's service territory.

INTERCONNECTION REQUIREMENTS

Except as otherwise provided in a generation Interconnection Agreement between the Company and Seller, if the QF is located within the Company's service territory, switching equipment capable of isolating the QF from the Company's system will be accessible to the Company at all times. At the Company's option, the Company may operate the switching equipment described above if, in the sole opinion of the Company, continued operation of the QF in connection with the utility's system may create or contribute to a system emergency.

INTERCONNECTION REQUIREMENTS (Continued)

The QF owner interconnecting with the Company's distribution system must comply with all requirements for interconnection as established pursuant to Commission rule, in the Company's Rules and Regulations (Rule C) or the Company's Interconnection Procedures contained in its FERC Open Access Transmission Tariff (OATT), as applicable. The Seller will bear full responsibility for the installation and safe operation of the interconnection facilities.

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE PRICING UNDER THE STANDARD PPA

A QF will be eligible to receive pricing under the Standard PPA if the nameplate capacity of the QF, together with any other electric generating facility using the same motive force, owned or controlled by the Same Person(s) or Affiliated Person(s), and located at the Same Site, does not exceed 10 MW. A Community-Based or Family-Owned QF is exempt from these restrictions.

Definition of Community-Based

- a. A community project (or a community sponsored project) must have a recognized and established organization located within the county of the project or within 50 miles of the project that has a genuine role in helping the project be developed and must have some not insignificant continuing role with or interest in the project after it is completed and placed in service.
- b. After excluding the passive investor whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit, the equity (ownership) interests in a community sponsored project must be owned in substantial percentage (80 percent or more) by the following persons (individuals and entities): (i) the sponsoring organization, or its controlled affiliates; (ii) members of the sponsoring organization (if it is a membership organization) or owners of the sponsorship organization (if it is privately owned); (iii) persons who live in the county in which the project is located or who live a county adjoining the county in which the project is located; or (iv) units of local government, charities, or other established nonprofit organizations active either in the county in which the project is located or active in a county adjoining the county in which the project is located.

Definition of Family-Owned

After excluding the ownership interest of the passive investor whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit, five or fewer individuals own 50 percent or more of the equity of the project entity, or fifteen or fewer individuals own 90 percent or more of the project entity. A "look through" rule applies to closely held entities that hold the project entity, so that equity held by LLCs, trusts, estates, corporations, partnerships or other similar entities is considered held by the equity owners of the look through entity. An individual is a natural person. In counting to five or fifteen, spouses or children of an equity owner of the project owner who also have an equity interest are aggregated and counted as a single individual.

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE PRICING UNDER THE STANDARD PPA (Continued)

Definition of Person(s) or Affiliated Person(s)

As used above, the term "Same Person(s)" or "Affiliated Person(s)" means a natural person or persons or any legal entity or entities sharing common ownership, management or acting jointly or in concert with or exercising influence over the policies or actions of another person or entity. However, two facilities will not be held to be owned or controlled by the Same Person(s) or Affiliated Person(s) solely because they are developed by a single entity.

Furthermore, two facilities will not be held to be owned or controlled by the Same Person(s) or Affiliated Person(s) if such common person or persons is a "passive investor" whose ownership interest in the QF is primarily related to utilizing production tax credits, green tag values and MACRS depreciation as the primary ownership benefit and the facilities at issue are independent family-owned or community-based projects. A unit of Oregon local government may also be a "passive investor" in a community-based project if the local governmental unit demonstrates that it will not have an equity ownership interest in or exercise any control over the management of the QF and that its only interest is a share of the cash flow from the QF, which share will not exceed 20%. The 20% cash flow share limit may only be exceeded for good cause shown and only with the prior approval of the Commission.

Definition of Same Site

For purposes of the foregoing, generating facilities are considered to be located at the same site as the QF for which qualification for pricing under the Standard PPA is sought if they are located within a five-mile radius of any generating facilities or equipment providing fuel or motive force associated with the QF for which qualification for pricing under the Standard PPA is sought.

Definition of Shared Interconnection and Infrastructure

QFs otherwise meeting the above-described separate ownership test and thereby qualified for entitlement to pricing under the Standard PPA will not be disqualified by utilizing an interconnection or other infrastructure not providing motive force or fuel that is shared with other QFs qualifying for pricing under the Standard PPA so long as the use of the shared interconnection complies with the interconnecting utility's safety and reliability standards, interconnection agreement requirements and Prudent Electrical Practices as that term is defined in the interconnecting utility's approved Standard PPA.

OTHER DEFINITIONS

Mid-C Index Price

As used in this schedule, the daily Mid-C Index Price shall be the Day Ahead Intercontinental Exchange ("ICE") for the bilateral OTC market for energy at the Mid-C Physical for Average

OTHER DEFINITIONS (Continued)

On-Peak Power and Average Off-Peak Power found on the following website: https://www.theice.com/products/OTC/Physical-Energy/Electricity. In the event ICE no longer publishes this index, PGE and the Seller agree to select an alternative successor index representative of the Mid-C trading hub.

Definition of RPS Attributes

As used in this schedule, RPS Attributes means all attributes related to the Net Output generated by the Facility that are required in order to provide PGE with "qualifying electricity," as that term is defined in Oregon's Renewable Portfolio Standard Act, Ore. Rev. Stat. 469A.010, in effect at the time of execution of this Agreement. RPS Attributes do not include Environmental Attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity and not needed to ensure that there are zero net emissions associated with the generation of electricity.

Definition of Environmental Attributes

As used in this schedule, Environmental Attributes shall mean any and all claims, credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical, or other substance to the air, soil or water. Environmental Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil, or water such as (subject to the foregoing) sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; and (2) any avoided emissions of carbon dioxide (CO2), methane (CH4), and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere.

Definition of Resource Sufficiency Period

This is the period from the current year through 2020.

Definition of Resource Deficiency Period

This is the period from 2021 through 2034.

Definition of Renewable Resource Sufficiency Period

This is the period from the current year through 2019.

Definition of Renewable Resource Deficiency Period

This is the period from 2020 through 2034.

SCHEDULE 201 (Concluded)

DISPUTE RESOLUTION

Upon request, the QF will provide the purchasing utility with documentation verifying the ownership, management and financial structure of the QF in reasonably sufficient detail to allow the utility to make an initial determination of whether or not the QF meets the above-described criteria for entitlement to pricing under the Standard PPA.

The QF may present disputes to the Commission for resolution using the following process:

The QF may file a complaint asking the Commission to adjudicate disputes regarding the formation of the standard contract. The QF may not file such a complaint during any 15-day period in which the utility has the obligation to respond, but must wait until the 15-day period has passed.

The utility may respond to the complaint within ten days of service.

The Commission will limit its review to the issues identified in the complaint and response, and utilize a process similar to the arbitration process adopted to facilitate the execution of interconnection agreements among telecommunications carriers. See OAR 860, Division 016. The administrative law judge will not act as an arbitrator.

SPECIAL CONDITIONS

- 1. Delivery of energy by Seller will be at a voltage, phase, frequency, and power factor as specified by the Company.
- 2. If the Seller also receives retail Electricity Service from the Company at the same location, any payments under this schedule will be credited to the Seller's retail Electricity Service bill. At the option of the Customer, any net credit over \$10.00 will be paid by check to the Customer.
- 3. Unless required by state or federal law, if the 1978 Public Utility Regulatory Policies Act (PURPA) is repealed, PPAs entered into pursuant to this schedule will not terminate prior to the Standard or Negotiated PPA's termination date.

TERM OF AGREEMENT

Not less than one year and not to exceed 20 years.

Blue Marmot/201 Talbott/53 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

STANDARD RENEWABLE OFF-SYSTEM VARIABLE POWER PURCHASE AGREEMENT

THIS AGREEMENT is between <u>Blue Marmot V LLC</u> ("Seller") and Portland General Electric Company ("PGE") (hereinafter each a "Party" or collectively, "Parties") and is effective upon execution by both Parties ("Effective Date").

RECITALS

Seller intends to construct, own, operate and maintain a <u>Solar</u> facility for the generation of electric power located in <u>Lake</u>, County, <u>Oregon at W 120.412 N 42.175</u> with a Nameplate Capacity Rating of <u>10000</u> kilowatt ("kW"), as further described in Exhibit A ("Facility"); and

Seller intends to operate the Facility as a "Qualifying Facility," as such term is defined in Section 3.1.3, below.

Seller shall sell and PGE shall purchase the entire Net Output, as such term is defined in Section 1.21, below, from the Facility in accordance with the terms and conditions of this Agreement.

AGREEMENT

NOW, THEREFORE, the Parties mutually agree as follows:

SECTION 1: DEFINITIONS

When used in this Agreement, the following terms shall have the following meanings:

- 1.1. "As-built Supplement" means the supplement to Exhibit A provided by Seller in accordance with Section 4.3 following completion of construction of the Facility, describing the Facility as actually built.
- 1.2. "Base Hours" is defined as the total number of hours in each Contract Year (8,760 or 8,784 for leap year)
- 1.3. "Billing Period" means from the start of the first day of each calendar month to the end of the last day of each calendar month.
- 1.4. "Cash Escrow" means an agreement by two parties to place money into the custody of a third party for delivery to a grantee only after the fulfillment of the conditions specified.
- 1.5. "Commercial Operation Date" means the date that the Facility is deemed by PGE to be fully operational and reliable. PGE may, at its discretion require, among other things, that all of the following events have occurred:
- 1.5.1. (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from a Licensed

Blue Marmot/201 Talbott/54 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

Professional Engineer ("LPE") acceptable to PGE in its reasonable judgment stating that the Facility is able to generate electric power reliably in accordance with the terms and conditions of this Agreement (certifications required under this Section 1.5 can be provided by one or more LPEs);

- 1.5.2. Start-Up Testing of the Facility has been completed in accordance with Section 1.36;
- 1.5.3. (facilities with nameplate under 500 kW exempt from following requirement) After PGE has received notice of completion of Start-Up Testing, PGE has received a certificate addressed to PGE from an LPE stating that the Facility has operated for testing purposes under this Agreement and was continuously mechanically available for operation for a minimum of 120 hours. The Facility must provide ten (10) working days written notice to PGE prior to the start of the initial testing period. If the mechanical availability of the Facility is interrupted during this initial testing period or any subsequent testing period, the Facility shall promptly start a new Test Period and provide PGE forty-eight (48) hours written notice prior to the start of such testing period;
- 1.5.4. (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from an LPE stating that all required interconnection facilities have been constructed and all required interconnection tests have been completed;
- 1.5.5. (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from an LPE stating that Seller has obtained all Required Facility Documents and, if requested by PGE in writing, has provided copies of any or all such requested Required Facility Documents;
- 1.5.6. PGE has received a copy of the executed Generation Interconnection and Transmission Agreements.
- 1.6. "Contract Price" means the applicable price, including on-peak and offpeak prices, as specified in the Schedule.
- 1.7. "Contract Year" means each twelve (12) month period commencing upon the Commercial Operation Date or its anniversary during the Term, except the final Contract Year will be the period from the last anniversary of the Commercial Operation Date during the Term until the end of the Term.
 - 1.8. "Effective Date" has the meaning set forth in Section 2.1.
- 1.9. "Environmental Attributes" shall mean any and all claims, credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical or other substance to the air, soil or water. Environmental Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil or water such as (subject to the foregoing) sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; and (2) any avoided emissions of carbon dioxide (CO2), methane (CH4), and other greenhouse gasses (GHGs) that have been determined by the United Nations

Blue Marmot/201 Talbott/55 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

Intergovernmental Panel on Climate Change to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere.

- 1.10. "Facility" has the meaning set forth in the Recitals.
- 1.11. "Generation Interconnection Agreement" means an agreement governing the interconnection of the Facility with Pacificorp electric system.
- 1.12. "Generation Unit" means each separate electrical generator that contributes toward Nameplate Capacity Rating included in Exhibit A. For solar facilities, a generating unit is a complete solar electrical generation system within the Facility that is able to generate and deliver energy to the Point of Delivery independent of other Generation Units within the same Facility.
- 1.13. "Letter of Credit" means an engagement by a bank or other person made at the request of a customer that the issuer will honor drafts or other demands for payment upon compliance with the conditions specified in the letter of credit.
- 1.14. "Licensed Professional Engineer" or "LPE" means a person who is licensed to practice engineering in the state where the Facility is located, who has no economic relationship, association, or nexus with the Seller, and who is not a representative of a consulting engineer, contractor, designer or other individual involved in the development of the Facility, or of a manufacturer or supplier of any equipment installed in the Facility. Such Licensed Professional Engineer shall be licensed in an appropriate engineering discipline for the required certification being made and be acceptable to PGE in its reasonable judgment.
- 1.15. "Lost Energy" means "Lost Energy" means ((the Guarantee of Mechanical Availability as set forth in 3.1.10 / MAP) X Net Output for a Calendar Year) Net Output for the Calendar Year. Lost Energy shall be zero unless the result of the calculation in this subsection results in a positive number.
- 1.16. "Lost Energy Value" means Lost Energy X the excess of the annual time-weighted average Mid-C Index Price for On Peak Hours and Off Peak Hours over the time weighted average Contract Price for On Peak and Off Peak Hours for the corresponding time period (provided that such excess shall not exceed the Contract Price and further provided that Lost Energy is deemed to be zero prior to reaching the Commercial Operation Date) plus any reasonable costs incurred by PGE to purchase replacement power and/or transmission to deliver the replacement power to the Point of Delivery (For Start-Up Lost Energy Value See 1.35).
- 1.17. "Mechanical Availability Percentage" or "MAP" shall mean that percentage for any Contract Year for the Facility calculated in accordance with the following formula:

MAP = 100 X (Operational Hours) /(Base Hours X Number of Units)

1.18. "Mid-C Index Price" means the Day Ahead Intercontinental Exchange ("ICE") index price for the bilateral OTC market for energy at the Mid-C Physical for Average On Peak Power and Average Off Peak Power found on the following website:

Blue Marmot/201 Talbott/56 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

https://www.theice.com/products/OTC/Physical-Energy/Electricity. In the event ICE no longer publishes this index, PGE and the Seller agree to select an alternative successor index representative of the Mid-C trading hub.

- 1.19. "Nameplate Capacity Rating" means the maximum capacity of the Facility as stated by the manufacturer, expressed in kW, which shall not exceed 10,000 kW.
- 1.20. "Net Dependable Capacity" means the maximum capacity the Facility can sustain over a specified period modified for seasonal limitations, if any, and reduced by the capacity required for station service or auxiliaries.
- 1.21. "Net Output" means all energy expressed in kWhs produced by the Facility, less station and other onsite use and less transformation and transmission losses.
- 1.22. "Number of Units" means the number of Generation Units in the Facility as specified in Exhibit A.
 - 1.23. "Off-Peak Hours" has the meaning provided in the Schedule.
 - 1.24. "On-Peak Hours" has the meaning provided in the Schedule.
- 1.25. "Operational Hours" for the Facility means the total across all Generation Units of the number of hours each of the Facility's Generation Units are potentially capable of producing power at its Nameplate Capacity Rating regardless of actual weather conditions, season and the time of day or night, without any mechanical operating constraint or restriction, and potentially capable of delivering such power to the Point of Delivery in a Contract Year. During up to, but not more than, two hundred (200) hours of Planned Maintenance during a Contract Year for each Generation Unit and hours during which an event of Force Majeure exists, a Generation Unit shall be considered potentially capable of delivering such power to the Point of Delivery. For example, in the absence of any Planned Maintenance beyond 200 hours on any Generation Unit or Event of Force Majeure, the Operational Hours for a wind farm with five (5) separate two (2) MW turbines would be 43,800 for a Contract Year.
- 1.26. "Planned Maintenance" means outages scheduled ninety (90) days in advance, with PGE's prior written consent, which shall not be unreasonably withheld.
 - 1.27. "Point of Delivery" means the PGE system.
- 1.28. "Pre-Commercial Operation Date Minimum Net Output" shall mean, unless such MWh is specifically set forth by Seller in Exhibit A, an amount in MWh equal to seventy-five percent (75%) of Nameplate Capacity Rating X thirty percent (30%) for a wind or other renewable QF or fifty percent (50%) for a solar QF X (whole months since the date selected in Section 2.2.1 / 12) X (8760 hours 200 hours (assumed Planned Maintenance)) for each month. If Seller has provided specific expected monthly Net Output amounts for the Facility in Exhibit A, "Pre-Commercial Operation Date Minimum Net Output" shall mean seventy-five percent (75%) X expected net output set forth in Exhibit A for each month.

Blue Marmot/201 Talbott/57 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

- 1.29. "Prime Rate" means the publicly announced prime rate or reference rate for commercial loans to large businesses with the highest credit rating in the United States in effect from time to time quoted by Citibank, N.A. If a Citibank, N.A. prime rate is not available, the applicable Prime Rate shall be the announced prime rate or reference rate for commercial loans in effect from time to time quoted by a bank with \$10 billion or more in assets in New York City, N.Y., selected by the Party to whom interest based on the prime rate is being paid.
- 1.30. "Prudent Electrical Practices" means those practices, methods, standards and acts engaged in or approved by a significant portion of the electric power industry in the Western Electricity Coordinating Council that at the relevant time period, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with good business practices, reliability, economy, safety and expedition, and which practices, methods, standards and acts reflect due regard for operation and maintenance standards recommended by applicable equipment suppliers and manufacturers, operational limits, and all applicable laws and regulations. Prudent Electrical Practices are not intended to be limited to the optimum practice, method, standard or act to the exclusion of all others, but rather to those practices, methods and acts generally acceptable or approved by a significant portion of the electric power generation industry in the relevant region, during the relevant period, as described in the immediate preceding sentence.
- 1.31. "Required Facility Documents" means all licenses, permits, authorizations, and agreements necessary for construction, operation, interconnection, and maintenance of the Facility including without limitation those set forth in Exhibit B.
- 1.32. "RPS Attributes" means all attributes related to the Net Output generated by the Facility that are required in order to provide PGE with "qualifying electricity," as that term is defined in Oregon's Renewable Portfolio Standard Act, Ore. Rev. Stat. 469A.010, in effect at the time of execution of this Agreement. RPS Attributes do not include Environmental Attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity and not needed to ensure that there are zero net emissions associated with the generation of electricity.
- 1.33. "Schedule" shall mean PGE Schedule 201 filed with the Oregon Public Utilities Commission ("Commission") in effect on the Effective Date of this Agreement and attached hereto as Exhibit D, the terms of which are hereby incorporated by reference.
- 1.34. "Senior Lien" means a prior lien which has precedence as to the property under the lien over another lien or encumbrance
- 1.35. "Start-Up Lost Energy Value" means for the period after the date specified in Section 2.2.2 but prior to achievement of the Commercial Operation Date: zero, unless the Net Output is less than the pro-rated Pre-Commercial Operation Date Minimum Net Output for the applicable delay period, and the time-weighted average of the delay period's Mid-C Index Price for On-Peak Hours and Off-Peak Hours is greater

Blue Marmot/201 Talbott/58 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

than the time-weighted average of the delay period's Contract Price for On-Peak Hours and Off-Peak Hours, in which case Startup Lost Energy Value equals: (pro-rated Pre-Commercial Operation Date Minimum Net Output for the applicable period - Net Output for the applicable period) X (the lower of: the time-weighted average of the Contract Price for On-Peak hours and Off-Peak Hours during the applicable period; or (the time-weighted average of the Mid-C Index Price for On-Peak Hours and Off-Peak Hours during the applicable period). The time-weighted average in this section will reflect the relative proportions of On-Peak Hours and Off-Peak Hours in each day.

- 1.36. "Start-Up Testing" means the completion of applicable required factory and start-up tests as set forth in Exhibit C.
- 1.37. "Step-in Rights" means the right of one party to assume an intervening position to satisfy all terms of an agreement in the event the other party fails to perform its obligations under the agreement.
- 1.38. "Term" shall mean the period beginning on the Effective Date and ending on the Termination Date.
- 1.39. "Test Period" shall mean a period of sixty (60) days or a commercially reasonable period determined by the Seller.
- 1.40. "Transmission Agreement" means an agreement executed by the Seller and the Transmission Provider(s) for Transmission Services.
- 1.41. "Transmission Curtailment" means a limitation on Seller's ability to deliver any portion of the scheduled energy to PGE due to the unavailability of transmission to the Point of Delivery (for any reason other than Force Majeure).
- 1.42. "Transmission Curtailment Replacement Energy Cost" means the greater of zero or the amount calculated as: ((Mid-C Index Price Contract Price) X curtailed energy) for periods of Transmission Curtailment.
- 1.43. "Transmission Provider(s)" means the signatory (other than the Seller) to the Transmission Agreement.
- 1.44. "Transmission Services" means any and all services (including but not limited to ancillary services and control area services) required for the firm transmission and delivery of Energy from the Facility to the Point of Delivery for a term not less than the Term of this Agreement.

References to Recitals, Sections, and Exhibits are to be the recitals, sections and exhibits of this Agreement.

SECTION 2: TERM; COMMERCIAL OPERATION DATE

2.1. This Agreement shall become effective upon execution by both Parties ("Effective Date").

- 2.2. Time is of the essence of this Agreement, and Seller's ability to meet certain requirements prior to the Commercial Operation Date and to complete all requirements to establish the Commercial Operation Date is critically important. Therefore,
 - 2.2.1. By 11/1/2019 Seller shall begin initial deliveries of Net Output; and
- 2.2.2. By 11/30/2019 Seller shall have completed all requirements under Section 1.5 and shall have established the Commercial Operation Date.
- 2.2.3. Unless the Parties agree in writing that a later Commercial Operation Date is reasonable and necessary, the Commercial Operation Date shall be no more than three (3) years from the Effective Date. PGE will not unreasonably withhold agreement to a Commercial Operation Date that is more than three (3) years from the Effective date if the Seller has demonstrated that a later Commercial Operation Date is reasonable and necessary.
- 2.3. This Agreement shall terminate on <u>20 years after effective date</u>, or the date the Agreement is terminated in accordance with Section 8 or 11, whichever is earlier ("Termination Date").

SECTION 3: REPRESENTATIONS AND WARRANTIES

- 3.1. Seller and PGE represent, covenant, and warrant as follows:
- 3.1.1. Seller warrants it is a <u>Limited liability company</u> duly organized under the laws of <u>Delaware</u>.
- 3.1.2. Seller warrants that the execution and delivery of this Agreement does not contravene any provision of, or constitute a default under, any indenture, mortgage, or other material agreement binding on Seller or any valid order of any court, or any regulatory agency or other body having authority to which Seller is subject.
- 3.1.3. Seller warrants that the Facility is and shall for the Term of this Agreement continue to be a "Qualifying Facility" ("QF") as that term is defined in the version of 18 C.F.R. Part 292 in effect on the Effective Date. Seller has provided the appropriate QF certification, which may include a Federal Energy Regulatory Commission ("FERC") self-certification to PGE prior to PGE's execution of this Agreement. At any time during the Term of this Agreement, PGE may require Seller to provide PGE with evidence satisfactory to PGE in its reasonable discretion that the Facility continues to qualify as a QF under all applicable requirements.
- 3.1.4. Seller warrants that it has not within the past two (2) years been the debtor in any bankruptcy proceeding, and Seller is and will continue to be for the Term of this Agreement current on all of its financial obligations.
- 3.1.5. Seller warrants that during the Term of this Agreement, all of Seller's right, title and interest in and to the Facility shall be free and clear of all liens and encumbrances other than liens and encumbrances arising from third-party financing of the Facility other than workers', mechanics', suppliers' or similar liens, or tax liens, in each case arising in the ordinary course of business that are either not yet due and

Blue Marmot/201 Talbott/60 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

payable or that have been released by means of a performance bond acceptable to PGE posted within eight (8) calendar days of the commencement of any proceeding to foreclose the lien.

- 3.1.6. Seller warrants that it will design and operate the Facility consistent with Prudent Electrical Practices.
- 3.1.7. Seller warrants that the Facility has a Nameplate Capacity Rating not greater than 10,000 kW.
 - 3.1.8. Seller warrants that Net Dependable Capacity of the Facility is 10,000 kW.
- 3.1.9. Seller estimates that the average annual Net Output to be delivered by the Facility to PGE is <u>21,999,568</u> kilowatt-hours ("kWh"), which amount PGE will include in its resource planning.
- 3.1.10. Seller represents and warrants that the Facility shall achieve the following Mechanical Availability Percentages ("Guarantee of Mechanical Availability"):
- 3.1.10.1. Ninety percent (90%) beginning in the first Contract Year and extending through the Term for the Facility, if the Facility was operational and sold electricity to PGE or another buyer prior to the Effective Date of this Agreement; or
- 3.1.10.2. Ninety percent (90%) beginning in Contract Year three and extending throughout the remainder of the Term.
- 3.1.10.3. Annually, within 90 days of the end of each Contract Year, Seller shall send to PGE a detailed written report demonstrating and providing evidence of the actual MAP for the previous Contract Year.
- 3.1.10.4. Seller's failure to meet the Guarantee of Mechanical Availability in a Calendar Year shall result in damages payable to PGE by Seller equal to the Lost Energy Value. PGE shall bill Seller for such damages in accordance with Section 7.
- 3.1.11. Seller will deliver from the Facility to PGE at the Point of Delivery Net Output not to exceed a maximum of 33,750,000 kWh of Net Output during each Contract Year ("Maximum Net Output"). The cost of delivering energy from the Facility to PGE is the sole responsibility of the Seller.
- 3.1.12. By the Commercial Operation Date, Seller has entered into a Generation Interconnection Agreement for a term not less than the term of this Agreement.
- 3.1.13. PGE warrants that it has not within the past two (2) years been the debtor in any bankruptcy proceeding, and PGE is and will continue to be for the Term of this Agreement current on all of its financial obligations.
- 3.1.14. Seller warrants that the Facility satisfies the eligibility requirements specified in the Definition of a Small Cogeneration Facility or Small Power Production Facility Eligible to Receive the Standard Renewable Rates and Standard Renewable PPA in PGE's Schedule and Seller will not make any changes in its ownership, control or management during the term of this Agreement that would cause it to not be in compliance with the Definition of a Small Cogeneration Facility or Small Power

Blue Marmot/201 Talbott/61 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

Production Facility Eligible to Receive the Standard Renewable Rates and Standard Renewable PPA in PGE's Schedule. Seller will provide, upon request by PGE not more frequently than every 36 months, such documentation and information as may be reasonably required to establish Seller's continued compliance with such Definition. PGE agrees to take reasonable steps to maintain the confidentiality of any portion of the above described documentation and information that the Seller identifies as confidential except PGE will provide all such confidential information to the Commission upon the Commission's request.

3.1.15. Seller warrants that it will comply with all requirements necessary for all Transferred RECs (as defined in Section 4.5) associated with Net Output to be issued, monitored, accounted for, and transferred by and through the Western Renewable Energy Generation System consistent with the provisions of OAR 330-160-0005 through OAR 330-160-0050. PGE warrants that it will reasonably cooperate in Seller's efforts to meet such requirements, including, for example serving as the qualified reporting entity for the Facility if the Facility is located in PGE's balancing authority.

SECTION 4: DELIVERY OF POWER, PRICE AND ENVIRONMENTAL ATTRIBUTES

- 4.1. Commencing on the Effective Date and continuing through the Term of this Agreement, Seller shall sell to PGE the entire Net Output delivered from the Facility at the Point of Delivery.
 - 4.2. PGE shall pay Seller the Contract Price for all delivered Net Output.
- 4.3. Upon completion of construction of the Facility, Seller shall provide PGE an As-built Supplement to specify the actual Facility as built. Seller shall not increase the Nameplate Capacity Rating above that specified in Exhibit A or increase the ability of the Facility to deliver Net Output in quantities in excess of the Net Dependable Capacity, or the Maximum Net Output as described in Section 3.1.11 above, through any means including, but not limited to, replacement, modification, or addition of existing equipment, except with prior written notice to PGE. In the event Seller increases the Nameplate Capacity Rating of the Facility to no more than 10,000 kW pursuant to this section, PGE shall pay the Contract Price for the additional delivered Net Output. In the event Seller increases the Nameplate Capacity Rating to greater than 10,000 kW, then Seller shall be required to enter into a new power purchase agreement for all delivered Net Output proportionally related to the increase of Nameplate Capacity above 10,000 kW.
- 4.4. Seller shall provide preschedules for all deliveries of energy hereunder, including identification of receiving and generating control areas, by 9:00:00 PPT on the last business day prior to the scheduled date of delivery. All energy shall be scheduled according to the most current North America Energy Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) scheduling rules and practices. The Parties' respective representatives shall maintain hourly real-time schedule coordination; provided, however, that in the absence of such coordination, the hourly schedule established by the exchange of preschedules shall be considered final. Seller and PGE shall maintain records of hourly energy schedules for accounting and

Blue Marmot/201 Talbott/62 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

operating purposes. The final E-Tag shall be the controlling evidence of the Parties' schedule. All energy shall be prescheduled according to customary WECC scheduling practices. Seller shall make commercially reasonable efforts to schedule in any hour an amount equal to its expected Net Output for such hour. Seller shall maintain a minimum of two years records of Net Output and shall agree to allow PGE to have access to such records and to imbalance information kept by the Transmission Provider.

From the start of the Renewable Resource Deficiency Period through the remainder of the Term of this Agreement, Seller shall provide and PGE shall acquire the RPS Attributes for the Contract Years as specified in the Schedule and Seller shall retain ownership of all other Environmental Attributes (if any). During the Renewable Resource Sufficiency Period, Seller shall retain all Environmental Attributes in accordance with the Schedule. The Contract Price includes full payment for the Net Output and any RPS Attributes transferred to PGE under this Agreement. With respect to Environmental Attributes not transferred to PGE under this Agreement ("Seller-Retained Environmental Attributes") Seller may report under §1605(b) of the Energy Policy Act of 1992 or under any applicable program as belonging to Seller any of the Seller-Retained Environmental Attributes, and PGE shall not report under such program that such Seller-Retained Environmental Attributes belong to it. With respect to RPS Attributes transferred to PGE under this Agreement ("Transferred RECs"), PGE may report under §1605(b) of the Energy Policy Act of 1992 or under any applicable program as belonging to it any of the Transferred RECs, and Seller shall not report under such program that such Transferred RECs belong to it.

SECTION 5: OPERATION AND CONTROL

- 5.1. Seller shall operate and maintain the Facility in a safe manner in accordance with the Generation Interconnection Agreement, and Prudent Electrical Practices. PGE shall have no obligation to purchase Net Output from the Facility to the extent the interconnection of the Facility to PGE's electric system is disconnected, suspended or interrupted, in whole or in part, pursuant to the Generation Interconnection Agreement, or to the extent generation curtailment is required as a result of Seller's noncompliance with the Generation Interconnection Agreement. Seller is solely responsible for the operation and maintenance of the Facility. PGE shall not, by reason of its decision to inspect or not to inspect the Facility, or by any action or inaction taken with respect to any such inspection, assume or be held responsible for any liability or occurrence arising from the operation and maintenance by Seller of the Facility.
- 5.2. Seller agrees to provide sixty (60) days advance written notice of any scheduled maintenance that would require shut down of the Facility for any period of time.
- 5.3. If the Facility ceases operation for unscheduled maintenance, Seller immediately shall notify PGE of the necessity of such unscheduled maintenance, the time when such maintenance has occurred or will occur, and the anticipated duration of such maintenance. Seller shall take all reasonable measures and exercise its best

Blue Marmot/201 Talbott/63 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

efforts to avoid unscheduled maintenance, to limit the duration of such unscheduled maintenance, and to perform unscheduled maintenance during Off-Peak hours.

SECTION 6: CREDITWORTHINESS

In the event Seller: a) is unable to represent or warrant as required by Section 3 that it has not been a debtor in any bankruptcy proceeding within the past two (2) years; b) becomes such a debtor during the Term; or c) is not or will not be current on all its financial obligations, Seller shall immediately notify PGE and shall promptly (and in no less than 10 days after notifying PGE) provide default security in an amount reasonably acceptable to PGE in one of the following forms: Senior Lien, Step-in Rights, a Cash Escrow or Letter of Credit. The amount of such default security that shall be acceptable to PGE shall be equal to: (annual On Peak Hours) X (On Peak Price – Off Peak Price) X (Net Dependable Capacity). Notwithstanding the foregoing, in the event Seller is not current on construction related financial obligations, Seller shall notify PGE of such delinquency and PGE may, in its discretion, grant an exception to the requirements to provide default security if the QF has negotiated financial arrangements with the construction loan lender that mitigate Seller's financial risk to PGE.

SECTION 7: BILLINGS, COMPUTATIONS AND PAYMENTS

- 7.1. On or before the thirtieth (30th) day following the end of each Billing Period, PGE shall send to Seller payment for Seller's deliveries of Net Output to PGE, together with computations supporting such payment. PGE may offset any such payment to reflect amounts owing from Seller to PGE pursuant to this Agreement and any other agreement related to the Facility between the Parties or otherwise. On or before the thirtieth (30th) day following the end of each Contract Year, PGE shall bill for any Lost Energy Value accrued pursuant to this Agreement.
- 7.2. Any amounts owing after the due date thereof shall bear interest at the Prime Rate plus two percent (2%) from the date due until paid; provided, however, that the interest rate shall at no time exceed the maximum rate allowed by applicable law.

SECTION 8: DEFAULT, REMEDIES AND TERMINATION

- 8.1. In addition to any other event that may constitute a default under this Agreement, the following events shall constitute defaults under this Agreement:
- 8.1.1. Breach by Seller or PGE of a representation or warranty, except for Section 3.1.4, set forth in this Agreement.
- 8.1.2 Seller's failure to provide default security, if required by Section 6, prior to delivery of any Net Output to PGE or within 10 days of notice.
- 8.1.3. Seller's failure to meet the Guarantee of Mechanical Availability established in Section 3.1.10 for two consecutive Contract Years or Seller's failure to provide any written report required by that section.
 - 8.1.4. If Seller is no longer a Qualifying Facility.
 - 8.1.5. Failure of PGE to make any required payment pursuant to Section 7.1.

Blue Marmot/201 Talbott/64 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

- 8.1.6. Seller's failure to meet the Commercial Operation Date.
- 8.2. In the event of a default under Section 8.1.6, PGE may provide Seller with written notice of default. Seller shall have one year in which to cure the default during which time the Seller shall pay PGE damages equal to the Lost Energy Value. If Seller is unable to cure the default, PGE may immediately terminate this Agreement as provided in Section 8.3. PGE's resource sufficiency/deficiency position shall have no bearing on PGE's right to terminate the Agreement under this Section 8.2.
- 8.3. In the event of a default hereunder, except as otherwise provided in this Agreement, the non-defaulting party may immediately terminate this Agreement at its sole discretion by delivering written notice to the other Party. In addition, the non-defaulting Party may pursue any and all legal or equitable remedies provided by law or pursuant to this Agreement including damages related to the need to procure replacement power. A termination hereunder shall be effective upon the date of delivery of notice, as provided in Section 20. The rights provided in this Section 8 are cumulative such that the exercise of one or more rights shall not constitute a waiver of any other rights.
- 8.4. If this Agreement is terminated as provided in this Section 8, PGE shall make all payments, within thirty (30) days, that, pursuant to the terms of this Agreement, are owed to Seller as of the time of receipt of notice of default. PGE shall not be required to pay Seller for any Net Output delivered by Seller after such notice of default.
- 8.5. In the event PGE terminates this Agreement pursuant to this Section 8, and Seller wishes to again sell Net Output to PGE following such termination, PGE in its sole discretion may require that Seller shall do so subject to the terms of this Agreement, including but not limited to the Contract Price until the Term of this Agreement (as set forth in Section 2.3) would have run in due course had the Agreement remained in effect. At such time Seller and PGE agree to execute a written document ratifying the terms of this Agreement.
- 8.6. Sections 8.1, 8.4, 8.5, 10, and 19.2 shall survive termination of this Agreement.

SECTION 9: TRANSMISSION CURTAILMENTS

- 9.1. Seller shall give PGE notice as soon as reasonably practicable of any Transmission Curtailment that is likely to affect Seller's ability to deliver any portion of energy scheduled pursuant to Section 4.4 of this Agreement.
- 9.2. If as the result of a Transmission Curtailment, Seller does not deliver any portion of energy (including real-time adjustments), scheduled pursuant to Section 4.4 of this Agreement, Seller shall pay PGE the Transmission Curtailment Replacement Energy Cost for the number of MWh of energy reasonably determined by PGE as the difference between (i) the scheduled energy that would have been delivered to PGE under this Agreement during the period of Transmission Curtailment and (ii) the actual energy, if any, that was delivered to PGE for the period.

Blue Marmot/201 Talbott/65 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

SECTION 10: INDEMNIFICATION AND LIABILITY

- 10.1. Seller agrees to defend, indemnify and hold harmless PGE, its directors, officers, agents, and representatives against and from any and all loss, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with Seller's delivery of electric power to PGE or with the facilities at or prior to the Point of Delivery, or otherwise arising out of this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PGE, Seller or others, excepting to the extent such loss, claim, action or suit may be caused by the negligence of PGE, its directors, officers, employees, agents or representatives.
- 10.2. PGE agrees to defend, indemnify and hold harmless Seller, its directors, officers, agents, and representatives against and from any and all loss, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with PGE's receipt of electric power from Seller or with the facilities at or after the Point of Delivery, or otherwise arising out of this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PGE, Seller or others, excepting to the extent such loss, claim, action or suit may be caused by the negligence of Seller, its directors, officers, employees, agents or representatives.
- 10.3. Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a Party to this Agreement. No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or to the public, nor affect the status of PGE as an independent public utility corporation or Seller as an independent individual or entity.
- 10.4. NEITHER PARTY SHALL BE LIABLE TO THE OTHER FOR SPECIAL, PUNITIVE, INDIRECT OR CONSEQUENTIAL DAMAGES, WHETHER ARISING FROM CONTRACT, TORT (INCLUDING NEGLIGENCE), STRICT LIABILITY OR OTHERWISE.

SECTION 11: INSURANCE

11.1. Prior to the connection of the Facility to PGE's electric system, provided such Facility has a design capacity of 200 kW or more, Seller shall secure and continuously carry for the Term hereof, with an insurance company or companies rated not lower than "B+" by the A. M. Best Company, insurance policies for bodily injury and property damage liability. Such insurance shall include provisions or endorsements naming PGE, it directors, officers and employees as additional insureds; provisions that such insurance is primary insurance with respect to the interest of PGE and that any insurance or self-insurance maintained by PGE is excess and not contributory insurance with the insurance required hereunder; a cross-liability or severability of

Blue Marmot/201 Talbott/66 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

insurance interest clause; and provisions that such policies shall not be canceled or their limits of liability reduced without thirty (30) days' prior written notice to PGE. Initial limits of liability for all requirements under this section shall be \$1,000,000 million single limit, which limits may be required to be increased or decreased by PGE as PGE determines in its reasonable judgment economic conditions or claims experience may warrant.

- 11.2. Prior to the connection of the Facility to PGE's electric system, provided such facility has a design capacity of 200 kW or more, Seller shall secure and continuously carry for the Term hereof, in an insurance company or companies rated not lower than "B+" by the A. M. Best Company, insurance acceptable to PGE against property damage or destruction in an amount not less than the cost of replacement of the Facility. Seller promptly shall notify PGE of any loss or damage to the Facility. Unless the Parties agree otherwise, Seller shall repair or replace the damaged or destroyed Facility, or if the facility is destroyed or substantially destroyed, it may terminate this Agreement. Such termination shall be effective upon receipt by PGE of written notice from Seller. Seller shall waive its insurers' rights of subrogation against PGE regarding Facility property losses.
- 11.3. Prior to the connection of the Facility to PGE's electric system and at all other times such insurance policies are renewed or changed, Seller shall provide PGE with a copy of each insurance policy required under this Section, certified as a true copy by an authorized representative of the issuing insurance company or, at the discretion of PGE, in lieu thereof, a certificate in a form satisfactory to PGE certifying the issuance of such insurance. If Seller fails to provide PGE with copies of such currently effective insurance policies or certificates of insurance, PGE at its sole discretion and without limitation of other remedies, may upon ten (10) days advance written notice by certified or registered mail to Seller either withhold payments due Seller until PGE has received such documents, or purchase the satisfactory insurance and offset the cost of obtaining such insurance from subsequent power purchase payments under this Agreement.

SECTION 12: FORCE MAJEURE

12.1. As used in this Agreement, "Force Majeure" or "an event of Force Majeure" means any cause beyond the reasonable control of the Seller or of PGE which, despite the exercise of due diligence, such Party is unable to prevent or overcome. By way of example, Force Majeure may include but is not limited to acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes, and other labor disturbances, earthquakes, fires, lightning, epidemics, sabotage, restraint by court order or other delay or failure in the performance as a result of any action or inaction on behalf of a public authority which by the exercise of reasonable foresight such Party could not reasonably have been expected to avoid and by the exercise of due diligence, it shall be unable to overcome, subject, in each case, to the requirements of the first sentence of this paragraph. Force Majeure, however, specifically excludes the cost or availability of resources to operate the Facility, changes in market conditions that affect

Blue Marmot/201 Talbott/67 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

the price of energy or transmission, wind or water droughts, and obligations for the payment of money when due.

- 12.2. If either Party is rendered wholly or in part unable to perform its obligation under this Agreement because of an event of Force Majeure, that Party shall be excused from whatever performance is affected by the event of Force Majeure to the extent and for the duration of the Force Majeure, after which such Party shall recommence performance of such obligation, provided that:
- 12.2.1. the non-performing Party, shall, promptly, but in any case within one (1) week after the occurrence of the Force Majeure, give the other Party written notice describing the particulars of the occurrence; and
- 12.2.2. the suspension of performance shall be of no greater scope and of no longer duration than is required by the Force Majeure; and
- 12.2.3. the non-performing Party uses its best efforts to remedy its inability to perform its obligations under this Agreement.
- 12.3. No obligations of either Party which arose before the Force Majeure causing the suspension of performance shall be excused as a result of the Force Majeure.
- 12.4. Neither Party shall be required to settle any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to the Party's best interests.

SECTION 13: SEVERAL OBLIGATIONS

Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership or joint venture or to impose a trust or partnership duty, obligation or liability between the Parties. If Seller includes two or more parties, each such party shall be jointly and severally liable for Seller's obligations under this Agreement.

SECTION 14: CHOICE OF LAW

This Agreement shall be interpreted and enforced in accordance with the laws of the state of Oregon, excluding any choice of law rules which may direct the application of the laws of another jurisdiction.

SECTION 15: PARTIAL INVALIDITY AND PURPA REPEAL

It is not the intention of the Parties to violate any laws governing the subject matter of this Agreement. If any of the terms of the Agreement are finally held or determined to be invalid, illegal or void as being contrary to any applicable law or public policy, all other terms of the Agreement shall remain in effect. If any terms are finally held or determined to be invalid, illegal or void, the Parties shall enter into negotiations concerning the terms affected by such decision for the purpose of achieving conformity with requirements of any applicable law and the intent of the Parties to this Agreement.

Blue Marmot/201 Talbott/68 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

In the event the Public Utility Regulatory Policies Act (PURPA) is repealed, this Agreement shall not terminate prior to the Termination Date, unless such termination is mandated by state or federal law.

SECTION 16: WAIVER

Any waiver at any time by either Party of its rights with respect to a default under this Agreement or with respect to any other matters arising in connection with this Agreement must be in writing, and such waiver shall not be deemed a waiver with respect to any subsequent default or other matter.

SECTION 17: GOVERNMENTAL JURISDICTION AND AUTHORIZATIONS

This Agreement is subject to the jurisdiction of those governmental agencies having control over either Party or this Agreement. Seller shall at all times maintain in effect all local, state and federal licenses, permits and other approvals as then may be required by law for the construction, operation and maintenance of the Facility, and shall provide upon request copies of the same to PGE.

SECTION 18: SUCCESSORS AND ASSIGNS

This Agreement and all of the terms hereof shall be binding upon and inure to the benefit of the respective successors and assigns of the Parties. No assignment hereof by either Party shall become effective without the written consent of the other Party being first obtained and such consent shall not be unreasonably withheld. Notwithstanding the foregoing, either Party may assign this Agreement without the other Party's consent as part of (a) a sale of all or substantially all of the assigning Party's assets, or (b) a merger, consolidation or other reorganization of the assigning Party.

SECTION 19: ENTIRE AGREEMENT

- 19.1. This Agreement supersedes all prior agreements, proposals, representations, negotiations, discussions or letters, whether oral or in writing, regarding PGE's purchase of Net Output from the Facility. No modification of this Agreement shall be effective unless it is in writing and signed by both Parties.
- 19.2. By executing this Agreement, Seller releases PGE from any third party claims related to the Facility, known or unknown, which may have arisen prior to the Effective Date.

SECTION 20: NOTICES

20.1. All notices except as otherwise provided in this Agreement shall be in writing, shall be directed as follows and shall be considered delivered if delivered in person or when deposited in the U.S. Mail, postage prepaid by certified or registered mail and return receipt requested:

To Seller: Blue Marmot V LLC

c/o EDP Renewables North America LLC;

Attention: General Counsel 808 Travis, Suite 700

Houston, Texas 77002

Blue Marmot/201 Talbott/69 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

To PGE: Contracts Manager

QF Contracts, 3WTC0306 PGE - 121 SW Salmon St. Portland, Oregon 97204

20.2 The Parties may change the person to whom such notices are addressed, or their addresses, by providing written notices thereof in accordance with this Section 20.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed in their respective names as of the Effective Date.

PGE
By:
Blue Marmot V LLC (Name Seller)
By:
Date:

Blue Marmot/201 Talbott/70 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

EXHIBIT A DESCRIPTION OF SELLER'S FACILITY

The facility will be a solar PV plant consisting of 38,715 polycrystalline modules of nominal 335W rating each. Total plant rating will be 12.97MWdc/10MWac.

Modules will be mounted to single-axis trackers.

Central inverter stations will be located at intermediate points in the PV field.

Modules will be evenly distributed to the inverter stations. The total inverter nameplate rating will be 10.0MWac. Each inverter will be directly coupled to a 34.5kV step-up transformer. The transformers will be connected to a 34.5kV AC collection system, which will feed into the plant switchgear.

The plant switchgear will feed a 34.5kV transmission line, which will run overhead approximately 3.1 miles to the PacifiCorp Mile-Hi Substation.

Inside the Mile-Hi Substation, the transmission line will connect to a new bay containing a facility-owned 34.5kV/115kV GSU transformer, associated breakers, switching, bus, and controls.

The facility-owned components at Mile-Hi substation are considered part of the self-certified qualifying facility.

Monthly	letail o	f firet wa	ar outpu																						
wiontiny o	ietali 0	i inzr Ae	ar outpu																						
Monthly Hour	ly sums lo	or E_Grid [MWh]																						
OH	1H	2H	3H	4H	5H	6H	7H	8H	9			1H	12H	T3H	14H	15H	16H	17H	18H	19H	20H	21H	22H	23H	Total
January	0	0	0	0	0	0	0	0	64	128	124	123	114		130	100		13	0	0	0	0	0	0	0 91
February	0	0	0	0	0	0	0	14	104	144	149	143	137					59	0	0	0	0	0	0	0 120
March	0	0	0	0	0	0	6	91	171	183	189	195	186	186	185	173	9 13	32	31	0	0	0	0	0	0 173
April	0	0	0	0	0	0	83	189	201	216	219	221	228	223	219	203	3 15	34	86	0	0	0	0	0	0 228
May	0	0	0	0	0	51	181	227	251	260	268	254	247					22	164	45	0	0	0	0	0 289
June	0	0	0	0	0	91	230	252	264	271	274	267	265						210	79	0	0	0	0	0 322
July	0	0	0	0	0	64	199	245	261	268	276	263	257						185	70	0	0	0	0	0 304
August	0	0	0	0	0	3	136	276	281	284	283	262	261	258	253	250	23	35	141	22	0	0	0	0	0 294
Septemb	0	0	0	0	0	0	68	203	233	237	238	231	230	233	232	21	9 1	71	45	0	0	0	0	0	0 234
October	0	0	0	0	0	0	2	105	200	205	195	192	191	198	199	18	0 6	84	0	0	0	0	0	0	0 173
Novembe	0	0	0	0	0	0	0	20	99	119	117	117	121	130	134	70	0	0	0	0	0	0	0	0	0 92
Decembe	0	0	0	0	0	0	0	0	55	97	38	102	101		130	- 68	5	0	0	0	0	0	0	0	0 77
Year	-2	-2	-2	-2	-2	209	904	1621	2184	2413	2430	2371	2336	2387	2381	214	155	56	860	215	-2	-2	-2	-2	-2 2398

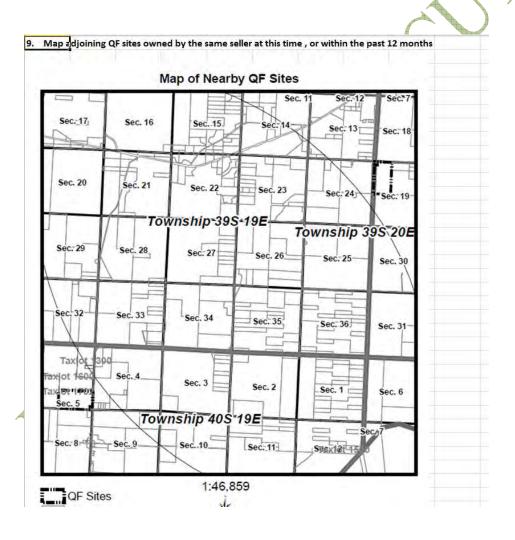


EXHIBIT B REQUIRED FACILITY DOCUMENTS

Sellers Generation Interconnection Agreement

Transmission Service Agreement with PacifiCorp

Purchase option agreement

Conditional Use Permit issued by Lake County

Any additional permits that might be required by Lake County or Oregon Department of Environmental Quality, including access permit, building and electric permits, and storm water prevention permit

FERC Qualifying Facility self-certification

EXHIBIT C START-UP TESTING

VISUAL AND MECHANICAL INSPECTIONS

INVERTER COMMISSIONING

ELECTRICAL OPERATION TESTS

SYSTEM MONITORING VERIFICATION

TRACKER VERIFICATION

INFRARED SCANS

BLOCK TESTING

72-HOUR FUNCTIONAL TEST

GRID MATCH TEST

POWER CHARACTERIZATION

REVENUE METER VERIFICATION

EXHIBIT D SCHEDULE



From: Shawn Davis <Shawn.Davis@pgn.com>
Sent: Monday, January 16, 2017 2:56 PM

To: Talbott, Will

Subject: RE: Blue Marmot V and Blue Marmot VI

Attachments: Blue Marmot V Standard Renewable Off System Executable Contract .pdf

Will,

After a quick second look it appears that I sent you the wrong contract for Marmot V. I've attached the correct version

Shawn P Davis |

Portland General Electric | 121 SW Salmon St. 3WTC0306 | Portland, Oregon 97204 | W: 503-464-7013 | F: 503-464-7608 |

E: shawn.davis@pgn.com

From: Shawn Davis

Sent: Thursday, January 12, 2017 4:37 PM

To: 'Talbott, Will'

Subject: RE: Blue Marmot V and Blue Marmot VI

Will,

Please find attached four documents. A letter and executable contract for Blue Marmot V and Blue Marmot VI. If you have any questions or concerns please do not hesitate to call.

Kindest regards,

Shawn P Davis |

Portland General Electric | 121 SW Salmon St. 3WTC0306 | Portland, Oregon 97204|

W: 503-464-7013 | F: 503-464-7608 |

E: shawn.davis@pgn.com

Blue Marmot/201 Talbott/76 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

STANDARD RENEWABLE OFF-SYSTEM VARIABLE POWER PURCHASE AGREEMENT

THIS AGREEMENT is between <u>Blue Marmot V LLC</u> ("Seller") and Portland General Electric Company ("PGE") (hereinafter each a "Party" or collectively, "Parties") and is effective upon execution by both Parties ("Effective Date").

RECITALS

Seller intends to construct, own, operate and maintain a <u>Solar</u> facility for the generation of electric power located in <u>Lake</u>, County, <u>Oregon at W 120.412 N 42.175</u> with a Nameplate Capacity Rating of <u>10000</u> kilowatt ("kW"), as further described in Exhibit A ("Facility"); and

Seller intends to operate the Facility as a "Qualifying Facility," as such term is defined in Section 3.1.3, below.

Seller shall sell and PGE shall purchase the entire Net Output, as such term is defined in Section 1.21, below, from the Facility in accordance with the terms and conditions of this Agreement.

AGREEMENT

NOW, THEREFORE, the Parties mutually agree as follows:

SECTION 1: DEFINITIONS

When used in this Agreement, the following terms shall have the following meanings:

- 1.1. "As-built Supplement" means the supplement to Exhibit A provided by Seller in accordance with Section 4.3 following completion of construction of the Facility, describing the Facility as actually built.
- 1.2. "Base Hours" is defined as the total number of hours in each Contract Year (8,760 or 8,784 for leap year)
- 1.3. "Billing Period" means from the start of the first day of each calendar month to the end of the last day of each calendar month.
- 1.4. "Cash Escrow" means an agreement by two parties to place money into the custody of a third party for delivery to a grantee only after the fulfillment of the conditions specified.
- 1.5. "Commercial Operation Date" means the date that the Facility is deemed by PGE to be fully operational and reliable. PGE may, at its discretion require, among other things, that all of the following events have occurred:
- 1.5.1. (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from a Licensed

Blue Marmot/201 Talbott/77 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

Professional Engineer ("LPE") acceptable to PGE in its reasonable judgment stating that the Facility is able to generate electric power reliably in accordance with the terms and conditions of this Agreement (certifications required under this Section 1.5 can be provided by one or more LPEs);

- 1.5.2. Start-Up Testing of the Facility has been completed in accordance with Section 1.36;
- 1.5.3. (facilities with nameplate under 500 kW exempt from following requirement) After PGE has received notice of completion of Start-Up Testing, PGE has received a certificate addressed to PGE from an LPE stating that the Facility has operated for testing purposes under this Agreement and was continuously mechanically available for operation for a minimum of 120 hours. The Facility must provide ten (10) working days written notice to PGE prior to the start of the initial testing period. If the mechanical availability of the Facility is interrupted during this initial testing period or any subsequent testing period, the Facility shall promptly start a new Test Period and provide PGE forty-eight (48) hours written notice prior to the start of such testing period;
- 1.5.4. (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from an LPE stating that all required interconnection facilities have been constructed and all required interconnection tests have been completed;
- 1.5.5. (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from an LPE stating that Seller has obtained all Required Facility Documents and, if requested by PGE in writing, has provided copies of any or all such requested Required Facility Documents;
- 1.5.6. PGE has received a copy of the executed Generation Interconnection and Transmission Agreements.
- 1.6. "Contract Price" means the applicable price, including on-peak and off-peak prices, as specified in the Schedule.
- 1.7. "Contract Year" means each twelve (12) month period commencing upon the Commercial Operation Date or its anniversary during the Term, except the final Contract Year will be the period from the last anniversary of the Commercial Operation Date during the Term until the end of the Term.
 - 1.8. "Effective Date" has the meaning set forth in Section 2.1.
- 1.9. "Environmental Attributes" shall mean any and all claims, credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical or other substance to the air, soil or water. Environmental Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil or water such as (subject to the foregoing) sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; and (2) any avoided emissions of carbon dioxide (CO2), methane (CH4), and other greenhouse gasses (GHGs) that have been determined by the United Nations

Blue Marmot/201 Talbott/78 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

Intergovernmental Panel on Climate Change to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere.

- 1.10. "Facility" has the meaning set forth in the Recitals.
- 1.11. "Generation Interconnection Agreement" means an agreement governing the interconnection of the Facility with **PacifiCorp** electric system.
- 1.12. "Generation Unit" means each separate electrical generator that contributes toward Nameplate Capacity Rating included in Exhibit A. For solar facilities, a generating unit is a complete solar electrical generation system within the Facility that is able to generate and deliver energy to the Point of Delivery independent of other Generation Units within the same Facility.
- 1.13. "Letter of Credit" means an engagement by a bank or other person made at the request of a customer that the issuer will honor drafts or other demands for payment upon compliance with the conditions specified in the letter of credit.
- 1.14. "Licensed Professional Engineer" or "LPE" means a person who is licensed to practice engineering in the state where the Facility is located, who has no economic relationship, association, or nexus with the Seller, and who is not a representative of a consulting engineer, contractor, designer or other individual involved in the development of the Facility, or of a manufacturer or supplier of any equipment installed in the Facility. Such Licensed Professional Engineer shall be licensed in an appropriate engineering discipline for the required certification being made and be acceptable to PGE in its reasonable judgment.
- 1.15. "Lost Energy" means "Lost Energy" means ((the Guarantee of Mechanical Availability as set forth in 3.1.10 / MAP) X Net Output for a Calendar Year) Net Output for the Calendar Year. Lost Energy shall be zero unless the result of the calculation in this subsection results in a positive number.
- 1.16. "Lost Energy Value" means Lost Energy X the excess of the annual time-weighted average Mid-C Index Price for On Peak Hours and Off Peak Hours over the time weighted average Contract Price for On Peak and Off Peak Hours for the corresponding time period (provided that such excess shall not exceed the Contract Price and further provided that Lost Energy is deemed to be zero prior to reaching the Commercial Operation Date) plus any reasonable costs incurred by PGE to purchase replacement power and/or transmission to deliver the replacement power to the Point of Delivery (For Start-Up Lost Energy Value See 1.35).
- 1.17. "Mechanical Availability Percentage" or "MAP" shall mean that percentage for any Contract Year for the Facility calculated in accordance with the following formula:

MAP = 100 X (Operational Hours) /(Base Hours X Number of Units)

1.18. "Mid-C Index Price" means the Day Ahead Intercontinental Exchange ("ICE") index price for the bilateral OTC market for energy at the Mid-C Physical for Average On Peak Power and Average Off Peak Power found on the following website:

Blue Marmot/201 Talbott/79 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

https://www.theice.com/products/OTC/Physical-Energy/Electricity. In the event ICE no longer publishes this index, PGE and the Seller agree to select an alternative successor index representative of the Mid-C trading hub.

- 1.19. "Nameplate Capacity Rating" means the maximum capacity of the Facility as stated by the manufacturer, expressed in kW, which shall not exceed 10,000 kW.
- 1.20. "Net Dependable Capacity" means the maximum capacity the Facility can sustain over a specified period modified for seasonal limitations, if any, and reduced by the capacity required for station service or auxiliaries.
- 1.21. "Net Output" means all energy expressed in kWhs produced by the Facility, less station and other onsite use and less transformation and transmission losses.
- 1.22. "Number of Units" means the number of Generation Units in the Facility as specified in Exhibit A.
 - 1.23. "Off-Peak Hours" has the meaning provided in the Schedule.
 - 1.24. "On-Peak Hours" has the meaning provided in the Schedule.
- 1.25. "Operational Hours" for the Facility means the total across all Generation Units of the number of hours each of the Facility's Generation Units are potentially capable of producing power at its Nameplate Capacity Rating regardless of actual weather conditions, season and the time of day or night, without any mechanical operating constraint or restriction, and potentially capable of delivering such power to the Point of Delivery in a Contract Year. During up to, but not more than, two hundred (200) hours of Planned Maintenance during a Contract Year for each Generation Unit and hours during which an event of Force Majeure exists, a Generation Unit shall be considered potentially capable of delivering such power to the Point of Delivery. For example, in the absence of any Planned Maintenance beyond 200 hours on any Generation Unit or Event of Force Majeure, the Operational Hours for a wind farm with five (5) separate two (2) MW turbines would be 43,800 for a Contract Year.
- 1.26. "Planned Maintenance" means outages scheduled ninety (90) days in advance, with PGE's prior written consent, which shall not be unreasonably withheld.
 - 1.27. "Point of Delivery" means the PGE system.
- 1.28. "Pre-Commercial Operation Date Minimum Net Output" shall mean, unless such MWh is specifically set forth by Seller in Exhibit A, an amount in MWh equal to seventy-five percent (75%) of Nameplate Capacity Rating X thirty percent (30%) for a wind or other renewable QF or fifty percent (50%) for a solar QF X (whole months since the date selected in Section 2.2.1 / 12) X (8760 hours 200 hours (assumed Planned Maintenance)) for each month. If Seller has provided specific expected monthly Net Output amounts for the Facility in Exhibit A, "Pre-Commercial Operation Date Minimum Net Output" shall mean seventy-five percent (75%) X expected net output set forth in Exhibit A for each month.

Blue Marmot/201 Talbott/80 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

- 1.29. "Prime Rate" means the publicly announced prime rate or reference rate for commercial loans to large businesses with the highest credit rating in the United States in effect from time to time quoted by Citibank, N.A. If a Citibank, N.A. prime rate is not available, the applicable Prime Rate shall be the announced prime rate or reference rate for commercial loans in effect from time to time quoted by a bank with \$10 billion or more in assets in New York City, N.Y., selected by the Party to whom interest based on the prime rate is being paid.
- 1.30. "Prudent Electrical Practices" means those practices, methods, standards and acts engaged in or approved by a significant portion of the electric power industry in the Western Electricity Coordinating Council that at the relevant time period, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with good business practices, reliability, economy, safety and expedition, and which practices, methods, standards and acts reflect due regard for operation and maintenance standards recommended by applicable equipment suppliers and manufacturers, operational limits, and all applicable laws and regulations. Prudent Electrical Practices are not intended to be limited to the optimum practice, method, standard or act to the exclusion of all others, but rather to those practices, methods and acts generally acceptable or approved by a significant portion of the electric power generation industry in the relevant region, during the relevant period, as described in the immediate preceding sentence.
- 1.31. "Required Facility Documents" means all licenses, permits, authorizations, and agreements necessary for construction, operation, interconnection, and maintenance of the Facility including without limitation those set forth in Exhibit B.
- 1.32. "RPS Attributes" means all attributes related to the Net Output generated by the Facility that are required in order to provide PGE with "qualifying electricity," as that term is defined in Oregon's Renewable Portfolio Standard Act, Ore. Rev. Stat. 469A.010, in effect at the time of execution of this Agreement. RPS Attributes do not include Environmental Attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity and not needed to ensure that there are zero net emissions associated with the generation of electricity.
- 1.33. "Schedule" shall mean PGE Schedule 201 filed with the Oregon Public Utilities Commission ("Commission") in effect on the Effective Date of this Agreement and attached hereto as Exhibit D, the terms of which are hereby incorporated by reference.
- 1.34. "Senior Lien" means a prior lien which has precedence as to the property under the lien over another lien or encumbrance
- 1.35. "Start-Up Lost Energy Value" means for the period after the date specified in Section 2.2.2 but prior to achievement of the Commercial Operation Date: zero, unless the Net Output is less than the pro-rated Pre-Commercial Operation Date Minimum Net Output for the applicable delay period, and the time-weighted average of the delay period's Mid-C Index Price for On-Peak Hours and Off-Peak Hours is greater

Blue Marmot/201 Talbott/81 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

than the time-weighted average of the delay period's Contract Price for On-Peak Hours and Off-Peak Hours, in which case Startup Lost Energy Value equals: (pro-rated Pre-Commercial Operation Date Minimum Net Output for the applicable period - Net Output for the applicable period) X (the lower of: the time-weighted average of the Contract Price for On-Peak hours and Off-Peak Hours during the applicable period; or (the time-weighted average of the Mid-C Index Price for On-Peak Hours and Off-Peak Hours during the applicable period). The time-weighted average in this section will reflect the relative proportions of On-Peak Hours and Off-Peak Hours in each day.

- 1.36. "Start-Up Testing" means the completion of applicable required factory and start-up tests as set forth in Exhibit C.
- 1.37. "Step-in Rights" means the right of one party to assume an intervening position to satisfy all terms of an agreement in the event the other party fails to perform its obligations under the agreement.
- 1.38. "Term" shall mean the period beginning on the Effective Date and ending on the Termination Date.
- 1.39. "Test Period" shall mean a period of sixty (60) days or a commercially reasonable period determined by the Seller.
- 1.40. "Transmission Agreement" means an agreement executed by the Seller and the Transmission Provider(s) for Transmission Services.
- 1.41. "Transmission Curtailment" means a limitation on Seller's ability to deliver any portion of the scheduled energy to PGE due to the unavailability of transmission to the Point of Delivery (for any reason other than Force Majeure).
- 1.42. "Transmission Curtailment Replacement Energy Cost" means the greater of zero or the amount calculated as: ((Mid-C Index Price Contract Price) X curtailed energy) for periods of Transmission Curtailment.
- 1.43. "Transmission Provider(s)" means the signatory (other than the Seller) to the Transmission Agreement.
- 1.44. "Transmission Services" means any and all services (including but not limited to ancillary services and control area services) required for the firm transmission and delivery of Energy from the Facility to the Point of Delivery for a term not less than the Term of this Agreement.

References to Recitals, Sections, and Exhibits are to be the recitals, sections and exhibits of this Agreement.

SECTION 2: TERM; COMMERCIAL OPERATION DATE

2.1. This Agreement shall become effective upon execution by both Parties ("Effective Date").

Blue Marmot/201 Talbott/82 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

- 2.2. Time is of the essence of this Agreement, and Seller's ability to meet certain requirements prior to the Commercial Operation Date and to complete all requirements to establish the Commercial Operation Date is critically important. Therefore,
 - 2.2.1. By 11/1/2019 Seller shall begin initial deliveries of Net Output; and
- 2.2.2. By <u>11/30/2019</u> Seller shall have completed all requirements under Section 1.5 and shall have established the Commercial Operation Date.
- 2.2.3. Unless the Parties agree in writing that a later Commercial Operation Date is reasonable and necessary, the Commercial Operation Date shall be no more than three (3) years from the Effective Date. PGE will not unreasonably withhold agreement to a Commercial Operation Date that is more than three (3) years from the Effective date if the Seller has demonstrated that a later Commercial Operation Date is reasonable and necessary.
- 2.3. This Agreement shall terminate on <u>18 years after effective date</u>, or the date the Agreement is terminated in accordance with Section 8 or 11, whichever is earlier ("Termination Date").

SECTION 3: REPRESENTATIONS AND WARRANTIES

- 3.1. Seller and PGE represent, covenant, and warrant as follows:
- 3.1.1. Seller warrants it is a <u>Limited liability company</u> duly organized under the laws of **Delaware**.
- 3.1.2. Seller warrants that the execution and delivery of this Agreement does not contravene any provision of, or constitute a default under, any indenture, mortgage, or other material agreement binding on Seller or any valid order of any court, or any regulatory agency or other body having authority to which Seller is subject.
- 3.1.3. Seller warrants that the Facility is and shall for the Term of this Agreement continue to be a "Qualifying Facility" ("QF") as that term is defined in the version of 18 C.F.R. Part 292 in effect on the Effective Date. Seller has provided the appropriate QF certification, which may include a Federal Energy Regulatory Commission ("FERC") self-certification to PGE prior to PGE's execution of this Agreement. At any time during the Term of this Agreement, PGE may require Seller to provide PGE with evidence satisfactory to PGE in its reasonable discretion that the Facility continues to qualify as a QF under all applicable requirements.
- 3.1.4. Seller warrants that it has not within the past two (2) years been the debtor in any bankruptcy proceeding, and Seller is and will continue to be for the Term of this Agreement current on all of its financial obligations.
- 3.1.5. Seller warrants that during the Term of this Agreement, all of Seller's right, title and interest in and to the Facility shall be free and clear of all liens and encumbrances other than liens and encumbrances arising from third-party financing of the Facility other than workers', mechanics', suppliers' or similar liens, or tax liens, in each case arising in the ordinary course of business that are either not yet due and

Blue Marmot/201 Talbott/83 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

payable or that have been released by means of a performance bond acceptable to PGE posted within eight (8) calendar days of the commencement of any proceeding to foreclose the lien.

- 3.1.6. Seller warrants that it will design and operate the Facility consistent with Prudent Electrical Practices.
- 3.1.7. Seller warrants that the Facility has a Nameplate Capacity Rating not greater than 10,000 kW.
 - 3.1.8. Seller warrants that Net Dependable Capacity of the Facility is **10,000** kW.
- 3.1.9. Seller estimates that the average annual Net Output to be delivered by the Facility to PGE is **21,999,568** kilowatt-hours ("kWh"), which amount PGE will include in its resource planning.
- 3.1.10. Seller represents and warrants that the Facility shall achieve the following Mechanical Availability Percentages ("Guarantee of Mechanical Availability"):
- 3.1.10.1. Ninety percent (90%) beginning in the first Contract Year and extending through the Term for the Facility, if the Facility was operational and sold electricity to PGE or another buyer prior to the Effective Date of this Agreement; or
- 3.1.10.2. Ninety percent (90%) beginning in Contract Year three and extending throughout the remainder of the Term.
- 3.1.10.3. Annually, within 90 days of the end of each Contract Year, Seller shall send to PGE a detailed written report demonstrating and providing evidence of the actual MAP for the previous Contract Year.
- 3.1.10.4. Seller's failure to meet the Guarantee of Mechanical Availability in a Calendar Year shall result in damages payable to PGE by Seller equal to the Lost Energy Value. PGE shall bill Seller for such damages in accordance with Section 7.
- 3.1.11. Seller will deliver from the Facility to PGE at the Point of Delivery Net Output not to exceed a maximum of <u>33,750,000</u> kWh of Net Output during each Contract Year ("Maximum Net Output"). The cost of delivering energy from the Facility to PGE is the sole responsibility of the Seller.
- 3.1.12. By the Commercial Operation Date, Seller has entered into a Generation Interconnection Agreement for a term not less than the term of this Agreement.
- 3.1.13. PGE warrants that it has not within the past two (2) years been the debtor in any bankruptcy proceeding, and PGE is and will continue to be for the Term of this Agreement current on all of its financial obligations.
- 3.1.14. Seller warrants that the Facility satisfies the eligibility requirements specified in the Definition of a Small Cogeneration Facility or Small Power Production Facility Eligible to Receive the Standard Renewable Rates and Standard Renewable PPA in PGE's Schedule and Seller will not make any changes in its ownership, control or management during the term of this Agreement that would cause it to not be in compliance with the Definition of a Small Cogeneration Facility or Small Power

Blue Marmot/201 Talbott/84 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

Production Facility Eligible to Receive the Standard Renewable Rates and Standard Renewable PPA in PGE's Schedule. Seller will provide, upon request by PGE not more frequently than every 36 months, such documentation and information as may be reasonably required to establish Seller's continued compliance with such Definition. PGE agrees to take reasonable steps to maintain the confidentiality of any portion of the above described documentation and information that the Seller identifies as confidential except PGE will provide all such confidential information to the Commission upon the Commission's request.

3.1.15. Seller warrants that it will comply with all requirements necessary for all Transferred RECs (as defined in Section 4.5) associated with Net Output to be issued, monitored, accounted for, and transferred by and through the Western Renewable Energy Generation System consistent with the provisions of OAR 330-160-0005 through OAR 330-160-0050. PGE warrants that it will reasonably cooperate in Seller's efforts to meet such requirements, including, for example serving as the qualified reporting entity for the Facility if the Facility is located in PGE's balancing authority.

SECTION 4: DELIVERY OF POWER, PRICE AND ENVIRONMENTAL ATTRIBUTES

- 4.1. Commencing on the Effective Date and continuing through the Term of this Agreement, Seller shall sell to PGE the entire Net Output delivered from the Facility at the Point of Delivery.
 - 4.2. PGE shall pay Seller the Contract Price for all delivered Net Output.
- 4.3. Upon completion of construction of the Facility, Seller shall provide PGE an As-built Supplement to specify the actual Facility as built. Seller shall not increase the Nameplate Capacity Rating above that specified in Exhibit A or increase the ability of the Facility to deliver Net Output in quantities in excess of the Net Dependable Capacity, or the Maximum Net Output as described in Section 3.1.11 above, through any means including, but not limited to, replacement, modification, or addition of existing equipment, except with prior written notice to PGE. In the event Seller increases the Nameplate Capacity Rating of the Facility to no more than 10,000 kW pursuant to this section, PGE shall pay the Contract Price for the additional delivered Net Output. In the event Seller increases the Nameplate Capacity Rating to greater than 10,000 kW, then Seller shall be required to enter into a new power purchase agreement for all delivered Net Output proportionally related to the increase of Nameplate Capacity above 10,000 kW.
- 4.4. Seller shall provide preschedules for all deliveries of energy hereunder, including identification of receiving and generating control areas, by 9:00:00 PPT on the last business day prior to the scheduled date of delivery. All energy shall be scheduled according to the most current North America Energy Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) scheduling rules and practices. The Parties' respective representatives shall maintain hourly real-time schedule coordination; provided, however, that in the absence of such coordination, the hourly schedule established by the exchange of preschedules shall be considered final. Seller and PGE shall maintain records of hourly energy schedules for accounting and

Blue Marmot/201 Talbott/85 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

operating purposes. The final E-Tag shall be the controlling evidence of the Parties' schedule. All energy shall be prescheduled according to customary WECC scheduling practices. Seller shall make commercially reasonable efforts to schedule in any hour an amount equal to its expected Net Output for such hour. Seller shall maintain a minimum of two years records of Net Output and shall agree to allow PGE to have access to such records and to imbalance information kept by the Transmission Provider.

From the start of the Renewable Resource Deficiency Period through the remainder of the Term of this Agreement, Seller shall provide and PGE shall acquire the RPS Attributes for the Contract Years as specified in the Schedule and Seller shall retain ownership of all other Environmental Attributes (if any). During the Renewable Resource Sufficiency Period, Seller shall retain all Environmental Attributes in accordance with the Schedule. The Contract Price includes full payment for the Net Output and any RPS Attributes transferred to PGE under this Agreement. With respect to Environmental Attributes not transferred to PGE under this Agreement ("Seller-Retained Environmental Attributes") Seller may report under §1605(b) of the Energy Policy Act of 1992 or under any applicable program as belonging to Seller any of the Seller-Retained Environmental Attributes, and PGE shall not report under such program that such Seller-Retained Environmental Attributes belong to it. With respect to RPS Attributes transferred to PGE under this Agreement ("Transferred RECs"), PGE may report under §1605(b) of the Energy Policy Act of 1992 or under any applicable program as belonging to it any of the Transferred RECs, and Seller shall not report under such program that such Transferred RECs belong to it.

SECTION 5: OPERATION AND CONTROL

- 5.1. Seller shall operate and maintain the Facility in a safe manner in accordance with the Generation Interconnection Agreement, and Prudent Electrical Practices. PGE shall have no obligation to purchase Net Output from the Facility to the extent the interconnection of the Facility to PGE's electric system is disconnected, suspended or interrupted, in whole or in part, pursuant to the Generation Interconnection Agreement, or to the extent generation curtailment is required as a result of Seller's noncompliance with the Generation Interconnection Agreement. Seller is solely responsible for the operation and maintenance of the Facility. PGE shall not, by reason of its decision to inspect or not to inspect the Facility, or by any action or inaction taken with respect to any such inspection, assume or be held responsible for any liability or occurrence arising from the operation and maintenance by Seller of the Facility.
- 5.2. Seller agrees to provide sixty (60) days advance written notice of any scheduled maintenance that would require shut down of the Facility for any period of time.
- 5.3. If the Facility ceases operation for unscheduled maintenance, Seller immediately shall notify PGE of the necessity of such unscheduled maintenance, the time when such maintenance has occurred or will occur, and the anticipated duration of such maintenance. Seller shall take all reasonable measures and exercise its best

Blue Marmot/201 Talbott/86 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

efforts to avoid unscheduled maintenance, to limit the duration of such unscheduled maintenance, and to perform unscheduled maintenance during Off-Peak hours.

SECTION 6: CREDITWORTHINESS

In the event Seller: a) is unable to represent or warrant as required by Section 3 that it has not been a debtor in any bankruptcy proceeding within the past two (2) years; b) becomes such a debtor during the Term; or c) is not or will not be current on all its financial obligations, Seller shall immediately notify PGE and shall promptly (and in no less than 10 days after notifying PGE) provide default security in an amount reasonably acceptable to PGE in one of the following forms: Senior Lien, Step-in Rights, a Cash Escrow or Letter of Credit. The amount of such default security that shall be acceptable to PGE shall be equal to: (annual On Peak Hours) X (On Peak Price – Off Peak Price) X (Net Dependable Capacity). Notwithstanding the foregoing, in the event Seller is not current on construction related financial obligations, Seller shall notify PGE of such delinquency and PGE may, in its discretion, grant an exception to the requirements to provide default security if the QF has negotiated financial arrangements with the construction loan lender that mitigate Seller's financial risk to PGE.

SECTION 7: BILLINGS, COMPUTATIONS AND PAYMENTS

- 7.1. On or before the thirtieth (30th) day following the end of each Billing Period, PGE shall send to Seller payment for Seller's deliveries of Net Output to PGE, together with computations supporting such payment. PGE may offset any such payment to reflect amounts owing from Seller to PGE pursuant to this Agreement and any other agreement related to the Facility between the Parties or otherwise. On or before the thirtieth (30th) day following the end of each Contract Year, PGE shall bill for any Lost Energy Value accrued pursuant to this Agreement.
- 7.2. Any amounts owing after the due date thereof shall bear interest at the Prime Rate plus two percent (2%) from the date due until paid; provided, however, that the interest rate shall at no time exceed the maximum rate allowed by applicable law.

SECTION 8: DEFAULT, REMEDIES AND TERMINATION

- 8.1. In addition to any other event that may constitute a default under this Agreement, the following events shall constitute defaults under this Agreement:
- 8.1.1. Breach by Seller or PGE of a representation or warranty, except for Section 3.1.4, set forth in this Agreement.
- 8.1.2. Seller's failure to provide default security, if required by Section 6, prior to delivery of any Net Output to PGE or within 10 days of notice.
- 8.1.3. Seller's failure to meet the Guarantee of Mechanical Availability established in Section 3.1.10 for two consecutive Contract Years or Seller's failure to provide any written report required by that section.
 - 8.1.4. If Seller is no longer a Qualifying Facility.
 - 8.1.5. Failure of PGE to make any required payment pursuant to Section 7.1.

Blue Marmot/201 Talbott/87 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

- 8.1.6. Seller's failure to meet the Commercial Operation Date.
- 8.2. In the event of a default under Section 8.1.6, PGE may provide Seller with written notice of default. Seller shall have one year in which to cure the default during which time the Seller shall pay PGE damages equal to the Lost Energy Value. If Seller is unable to cure the default, PGE may immediately terminate this Agreement as provided in Section 8.3. PGE's resource sufficiency/deficiency position shall have no bearing on PGE's right to terminate the Agreement under this Section 8.2.
- 8.3. In the event of a default hereunder, except as otherwise provided in this Agreement, the non-defaulting party may immediately terminate this Agreement at its sole discretion by delivering written notice to the other Party. In addition, the non-defaulting Party may pursue any and all legal or equitable remedies provided by law or pursuant to this Agreement including damages related to the need to procure replacement power. A termination hereunder shall be effective upon the date of delivery of notice, as provided in Section 20. The rights provided in this Section 8 are cumulative such that the exercise of one or more rights shall not constitute a waiver of any other rights.
- 8.4. If this Agreement is terminated as provided in this Section 8, PGE shall make all payments, within thirty (30) days, that, pursuant to the terms of this Agreement, are owed to Seller as of the time of receipt of notice of default. PGE shall not be required to pay Seller for any Net Output delivered by Seller after such notice of default.
- 8.5. In the event PGE terminates this Agreement pursuant to this Section 8, and Seller wishes to again sell Net Output to PGE following such termination, PGE in its sole discretion may require that Seller shall do so subject to the terms of this Agreement, including but not limited to the Contract Price until the Term of this Agreement (as set forth in Section 2.3) would have run in due course had the Agreement remained in effect. At such time Seller and PGE agree to execute a written document ratifying the terms of this Agreement.
- 8.6. Sections 8.1, 8.4, 8.5, 10, and 19.2 shall survive termination of this Agreement.

SECTION 9: TRANSMISSION CURTAILMENTS

- 9.1. Seller shall give PGE notice as soon as reasonably practicable of any Transmission Curtailment that is likely to affect Seller's ability to deliver any portion of energy scheduled pursuant to Section 4.4 of this Agreement.
- 9.2. If as the result of a Transmission Curtailment, Seller does not deliver any portion of energy (including real-time adjustments), scheduled pursuant to Section 4.4 of this Agreement, Seller shall pay PGE the Transmission Curtailment Replacement Energy Cost for the number of MWh of energy reasonably determined by PGE as the difference between (i) the scheduled energy that would have been delivered to PGE under this Agreement during the period of Transmission Curtailment and (ii) the actual energy, if any, that was delivered to PGE for the period.

Blue Marmot/201 Talbott/88 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

SECTION 10: INDEMNIFICATION AND LIABILITY

- 10.1. Seller agrees to defend, indemnify and hold harmless PGE, its directors, officers, agents, and representatives against and from any and all loss, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with Seller's delivery of electric power to PGE or with the facilities at or prior to the Point of Delivery, or otherwise arising out of this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PGE, Seller or others, excepting to the extent such loss, claim, action or suit may be caused by the negligence of PGE, its directors, officers, employees, agents or representatives.
- 10.2. PGE agrees to defend, indemnify and hold harmless Seller, its directors, officers, agents, and representatives against and from any and all loss, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with PGE's receipt of electric power from Seller or with the facilities at or after the Point of Delivery, or otherwise arising out of this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PGE, Seller or others, excepting to the extent such loss, claim, action or suit may be caused by the negligence of Seller, its directors, officers, employees, agents or representatives.
- 10.3. Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a Party to this Agreement. No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or to the public, nor affect the status of PGE as an independent public utility corporation or Seller as an independent individual or entity.
- 10.4. NEITHER PARTY SHALL BE LIABLE TO THE OTHER FOR SPECIAL, PUNITIVE, INDIRECT OR CONSEQUENTIAL DAMAGES, WHETHER ARISING FROM CONTRACT, TORT (INCLUDING NEGLIGENCE), STRICT LIABILITY OR OTHERWISE.

SECTION 11: INSURANCE

11.1. Prior to the connection of the Facility to PGE's electric system, provided such Facility has a design capacity of 200 kW or more, Seller shall secure and continuously carry for the Term hereof, with an insurance company or companies rated not lower than "B+" by the A. M. Best Company, insurance policies for bodily injury and property damage liability. Such insurance shall include provisions or endorsements naming PGE, it directors, officers and employees as additional insureds; provisions that such insurance is primary insurance with respect to the interest of PGE and that any insurance or self-insurance maintained by PGE is excess and not contributory insurance with the insurance required hereunder; a cross-liability or severability of

Blue Marmot/201 Talbott/89 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

insurance interest clause; and provisions that such policies shall not be canceled or their limits of liability reduced without thirty (30) days' prior written notice to PGE. Initial limits of liability for all requirements under this section shall be \$1,000,000 million single limit, which limits may be required to be increased or decreased by PGE as PGE determines in its reasonable judgment economic conditions or claims experience may warrant.

- 11.2. Prior to the connection of the Facility to PGE's electric system, provided such facility has a design capacity of 200 kW or more, Seller shall secure and continuously carry for the Term hereof, in an insurance company or companies rated not lower than "B+" by the A. M. Best Company, insurance acceptable to PGE against property damage or destruction in an amount not less than the cost of replacement of the Facility. Seller promptly shall notify PGE of any loss or damage to the Facility. Unless the Parties agree otherwise, Seller shall repair or replace the damaged or destroyed Facility, or if the facility is destroyed or substantially destroyed, it may terminate this Agreement. Such termination shall be effective upon receipt by PGE of written notice from Seller. Seller shall waive its insurers' rights of subrogation against PGE regarding Facility property losses.
- 11.3. Prior to the connection of the Facility to PGE's electric system and at all other times such insurance policies are renewed or changed, Seller shall provide PGE with a copy of each insurance policy required under this Section, certified as a true copy by an authorized representative of the issuing insurance company or, at the discretion of PGE, in lieu thereof, a certificate in a form satisfactory to PGE certifying the issuance of such insurance. If Seller fails to provide PGE with copies of such currently effective insurance policies or certificates of insurance, PGE at its sole discretion and without limitation of other remedies, may upon ten (10) days advance written notice by certified or registered mail to Seller either withhold payments due Seller until PGE has received such documents, or purchase the satisfactory insurance and offset the cost of obtaining such insurance from subsequent power purchase payments under this Agreement.

SECTION 12: FORCE MAJEURE

12.1. As used in this Agreement, "Force Majeure" or "an event of Force Majeure" means any cause beyond the reasonable control of the Seller or of PGE which, despite the exercise of due diligence, such Party is unable to prevent or overcome. By way of example, Force Majeure may include but is not limited to acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes, and other labor disturbances, earthquakes, fires, lightning, epidemics, sabotage, restraint by court order or other delay or failure in the performance as a result of any action or inaction on behalf of a public authority which by the exercise of reasonable foresight such Party could not reasonably have been expected to avoid and by the exercise of due diligence, it shall be unable to overcome, subject, in each case, to the requirements of the first sentence of this paragraph. Force Majeure, however, specifically excludes the cost or availability of resources to operate the Facility, changes in market conditions that affect

Blue Marmot/201 Talbott/90 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

the price of energy or transmission, wind or water droughts, and obligations for the payment of money when due.

- 12.2. If either Party is rendered wholly or in part unable to perform its obligation under this Agreement because of an event of Force Majeure, that Party shall be excused from whatever performance is affected by the event of Force Majeure to the extent and for the duration of the Force Majeure, after which such Party shall recommence performance of such obligation, provided that:
- 12.2.1. the non-performing Party, shall, promptly, but in any case within one (1) week after the occurrence of the Force Majeure, give the other Party written notice describing the particulars of the occurrence; and
- 12.2.2. the suspension of performance shall be of no greater scope and of no longer duration than is required by the Force Majeure; and
- 12.2.3. the non-performing Party uses its best efforts to remedy its inability to perform its obligations under this Agreement.
- 12.3. No obligations of either Party which arose before the Force Majeure causing the suspension of performance shall be excused as a result of the Force Majeure.
- 12.4. Neither Party shall be required to settle any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to the Party's best interests.

SECTION 13: SEVERAL OBLIGATIONS

Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership or joint venture or to impose a trust or partnership duty, obligation or liability between the Parties. If Seller includes two or more parties, each such party shall be jointly and severally liable for Seller's obligations under this Agreement.

SECTION 14: CHOICE OF LAW

This Agreement shall be interpreted and enforced in accordance with the laws of the state of Oregon, excluding any choice of law rules which may direct the application of the laws of another jurisdiction.

SECTION 15: PARTIAL INVALIDITY AND PURPA REPEAL

It is not the intention of the Parties to violate any laws governing the subject matter of this Agreement. If any of the terms of the Agreement are finally held or determined to be invalid, illegal or void as being contrary to any applicable law or public policy, all other terms of the Agreement shall remain in effect. If any terms are finally held or determined to be invalid, illegal or void, the Parties shall enter into negotiations concerning the terms affected by such decision for the purpose of achieving conformity with requirements of any applicable law and the intent of the Parties to this Agreement.

Blue Marmot/201 Talbott/91 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

In the event the Public Utility Regulatory Policies Act (PURPA) is repealed, this Agreement shall not terminate prior to the Termination Date, unless such termination is mandated by state or federal law.

SECTION 16: WAIVER

Any waiver at any time by either Party of its rights with respect to a default under this Agreement or with respect to any other matters arising in connection with this Agreement must be in writing, and such waiver shall not be deemed a waiver with respect to any subsequent default or other matter.

SECTION 17: GOVERNMENTAL JURISDICTION AND AUTHORIZATIONS

This Agreement is subject to the jurisdiction of those governmental agencies having control over either Party or this Agreement. Seller shall at all times maintain in effect all local, state and federal licenses, permits and other approvals as then may be required by law for the construction, operation and maintenance of the Facility, and shall provide upon request copies of the same to PGE.

SECTION 18: SUCCESSORS AND ASSIGNS

This Agreement and all of the terms hereof shall be binding upon and inure to the benefit of the respective successors and assigns of the Parties. No assignment hereof by either Party shall become effective without the written consent of the other Party being first obtained and such consent shall not be unreasonably withheld. Notwithstanding the foregoing, either Party may assign this Agreement without the other Party's consent as part of (a) a sale of all or substantially all of the assigning Party's assets, or (b) a merger, consolidation or other reorganization of the assigning Party.

SECTION 19: ENTIRE AGREEMENT

- 19.1. This Agreement supersedes all prior agreements, proposals, representations, negotiations, discussions or letters, whether oral or in writing, regarding PGE's purchase of Net Output from the Facility. No modification of this Agreement shall be effective unless it is in writing and signed by both Parties.
- 19.2. By executing this Agreement, Seller releases PGE from any third party claims related to the Facility, known or unknown, which may have arisen prior to the Effective Date.

SECTION 20: NOTICES

20.1. All notices except as otherwise provided in this Agreement shall be in writing, shall be directed as follows and shall be considered delivered if delivered in person or when deposited in the U.S. Mail, postage prepaid by certified or registered mail and return receipt requested:

To Seller: Blue Marmot V LLC

c/o EDP Renewables North America LLC;

Attention: General Counsel

808 Travis, Suite 700 Houston, Texas 77002 Blue Marmot/201 Talbott/92 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

To PGE: Contracts Manager

QF Contracts, 3WTC0306 PGE - 121 SW Salmon St. Portland, Oregon 97204

20.2 The Parties may change the person to whom such notices are addressed, or their addresses, by providing written notices thereof in accordance with this Section 20.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed in their respective names as of the Effective Date.

PGE
By:
Name:
Title:
Date:
Blue Marmot V LLC
(Name Seller)
Ву:
Name:
Title:
Date:

Blue Marmot/201 Talbott/93 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

EXHIBIT A DESCRIPTION OF SELLER'S FACILITY

The facility will be a solar PV plant consisting of 38,715 polycrystalline modules of nominal 335W rating each. Total plant rating will be 12.97MWdc/10MWac.

Modules will be mounted to single-axis trackers.

Central inverter stations will be located at intermediate points in the PV field.

Modules will be evenly distributed to the inverter stations. The total inverter nameplate rating will be 10.0MWac. Each inverter will be directly coupled to a 34.5kV step-up transformer. The transformers will be connected to a 34.5kV AC collection system, which will feed into the plant switchgear.

The plant switchgear will feed a 34.5kV transmission line, which will run overhead approximately 3.1 miles to the PacifiCorp Mile-Hi Substation.

Inside the Mile-Hi Substation, the transmission line will connect to a new bay containing a facility-owned 34.5kV/115kV GSU transformer, associated breakers, switching, bus, and controls.

The facility-owned components at Mile-Hi substation are considered part of the self-certified qualifying facility.

onthly de	etail o	f first y	ear ou	tput																								
thly Hourly	sums	or E_Grid																										
0H	11-	2	H	3Н	4H	SH	6H	7	H 8		9H	10H	11H	12		13H	14H	15H	16	H 1	7H 18H	19H	20H	21H	22H	23H	1	otal
uary	0	0	0		0	0	0	0	0	64	128			123	114	122			100	13	0	0	0	0	0	0	0	918
ruary	0	0	0		0	0	0	0	14	104	144	14		143	137	153			147	59	0	0	0	0	0	0	0	1201
ch	0	0	0		0	0	0	6	91	171	183	1	89	195	186	186	18	5	179	132	31	0	0	0	0	0	0	1734
1	0	0	0		0	0	0	83	189	201	216	2	19	221	228	223	21	9 3	209	194	86	0	0	0	0	0	0	2288
	0	0	0		0	0	51	181	227	251	260	21	68	254	247	242	24	4 :	239	222	164	45	0	0	0	0	0	2895
e	0	0	0		0	0	91	230	252	264	271	2	74	267	265	263	26	2 3	252	243	210	79	0	0	0	0	0	3223
	0	0	0		0	0	64	199	245	261	268	2	76	263	257	258	24	3 :	229	224	185	70	0	0	0	0	0	3042
ust	0	0	0		0	0	3	136	276	281	284	21	83	262	261	258	25	3 :	250	235	141	22	0	0	0	0	0	2945
temb	0	0	0		0	0	0	68	203	233	237	2	38	231	230	233	23	2	219	171	45	0	0	0	0	0	0	2340
ober	0	0	0		0	0	0	2	105	200	205	1	95	192	191	198	19	9	180	64	0	0	0	0	0	0	0	1731
embe	0	0	0		0	0	0	0	20	99	119		17	117	121	130			70	0	0	0	0	0	0	0	0	927
embe	0	0	0		0	0	0	0	0	55	97	- 1	98	102	101	122	13	D	66	0	0	0	0	0	0	0	0	771
1	-2	-2	-2		-2	-2	209	904	1621	2184	2413	24	30 2	2371	2336	2387	238	1 2	140	1556	860	215	-2	-2	-2	-2	-2	23987
					-		200	501	102.	2101	2410				2000	2001	200			1000	000	2.13		-				

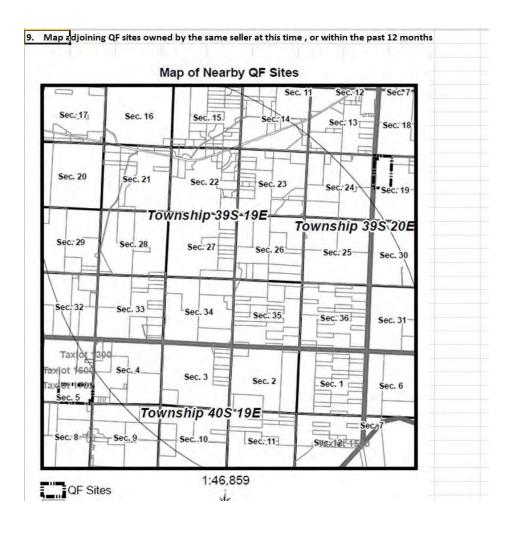


EXHIBIT B REQUIRED FACILITY DOCUMENTS

Sellers Generation Interconnection Agreement

Transmission Service Agreement with PacifiCorp

Purchase option agreement

Conditional Use Permit issued by Lake County

Any additional permits that might be required by Lake County or Oregon Department of Environmental Quality, including access permit, building and electric permits, and storm water prevention permit

FERC Qualifying Facility self-certification

EXHIBIT C START-UP TESTING

VISUAL AND MECHANICAL INSPECTIONS

INVERTER COMMISSIONING

ELECTRICAL OPERATION TESTS

SYSTEM MONITORING VERIFICATION

TRACKER VERIFICATION

INFRARED SCANS

BLOCK TESTING

72-HOUR FUNCTIONAL TEST

GRID MATCH TEST

POWER CHARACTERIZATION

REVENUE METER VERIFICATION

REACTIVE POWER TEST

POWER OUTPUT TEST - PLANT PERFORMANCE AND ACCEPTANCE

EXHIBIT D SCHEDULE

SCHEDULE 201 QUALIFYING FACILITY 10 MW or LESS AVOIDED COST POWER PURCHASE INFORMATION

PURPOSE

To provide information about Standard Avoided Costs and Renewable Avoided Costs, Standard Power Purchase Agreements (PPA) and Negotiated PPAs, power purchase prices and price options for power delivered by a Qualifying Facility (QF) to the Company with nameplate capacity of 10,000 kW (10MW) or less.

AVAILABLE

To owners of QFs making sales of electricity to the Company in the State of Oregon (Seller).

APPLICABLE

For power purchased from small power production or cogeneration facilities that are QFs as defined in 18 Code of Federal Regulations (CFR) Section 292, that meet the eligibility requirements described herein and where the energy is delivered to the Company's system and made available for Company purchase pursuant to a Standard PPA.

ESTABLISHING CREDITWORTHINESS

The Seller must establish creditworthiness prior to service under this schedule. For a Standard PPA, a Seller may establish creditworthiness with a written acknowledgment that it is current on all existing debt obligations and that it was not a debtor in a bankruptcy proceeding within the preceding 24 months. If the Seller is not able to establish creditworthiness, the Seller must provide security deemed sufficient by the Company as set forth in the Standard PPA.

POWER PURCHASE INFORMATION

A Seller may call the Power Production Coordinator at (503) 464-8000 to obtain more information about being a Seller or how to apply for service under this schedule.

PPA

In accordance with terms set forth in this schedule and the Commission's Rules as applicable, the Company will purchase any Energy in excess of station service (power necessary to produce generation) and amounts attributable to conversion losses, which are made available from the Seller.

A Seller must execute a PPA with the Company prior to delivery of power to the Company. The agreement will have a term of up to 20 years as selected by the QF.

A QF with a nameplate capacity rating of 10 MW or less as defined herein may elect the option of a Standard PPA.

PPA (Continued)

Any Seller may elect to negotiate a PPA with the Company. Such negotiation will comply with the requirements of the Federal Energy Regulatory Commission (FERC), and the Commission including the guidelines in Order No. 07-360, and Schedule 202. Negotiations for power purchase pricing will be based on either the filed Standard Avoided Costs or Renewable Avoided Costs in effect at that time.

STANDARD PPA (Nameplate capacity of 10 MW or less)

A Seller choosing a Standard PPA will complete all informational and price option selection requirements in the applicable Standard PPA and submit the executed Agreement to the Company prior to service under this schedule. The Standard PPA is available at www.portlandgeneral.com. The available Standard PPAs are:

- Standard In-System Non-Variable Power Purchase Agreement
- Standard Off-System Non-Variable Power Purchase Agreement
- Standard In-System Variable Power Purchase Agreement
- Standard Off-System Variable Power Purchase Agreement
- Standard Renewable In-System Non-Variable Power Purchase Agreement
- Standard Renewable Off-System Non-Variable Power Purchase Agreement
- Standard Renewable In-System Variable Power Purchase Agreement
- Standard Renewable Off-System Variable Power Purchase Agreement

The Standard PPAs applicable to variable resources are available only to QFs utilizing wind, solar or run of river hydro as the primary motive force.

GUIDELINES FOR 10 MW OR LESS FACILITIES ELECTING STANDARD PPA

To execute the Standard PPA the Seller must complete all of the general project information requested in the applicable Standard PPA.

When all information required in the Standard PPA has been received in writing from the Seller, the Company will respond within 15 business days with a draft Standard PPA.

The Seller may request in writing that the Company prepare a final draft Standard PPA. The Company will respond to this request within 15 business days. In connection with such request, the QF must provide the Company with any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft Standard PPA.

When both parties are in full agreement as to all terms and conditions of the draft Standard PPA, the Company will prepare and forward to the Seller a final executable version of the agreement within 15 business days. Following the Company's execution, an executed copy will be returned to the Seller. Prices and other terms and conditions in the PPA will not be final and binding until the Standard PPA has been executed by both parties.

OFF-SYSTEM PPA

A Seller with a facility that interconnects with an electric system other than the Company's electric system may enter into a PPA with the Company after following the applicable Standard or Negotiated PPA guidelines and making the arrangements necessary for transmission of power to the Company's system.

BASIS FOR POWER PURCHASE PRICE

AVOIDED COST SUMMARY

The power purchase prices are based on either the Company's Standard Avoided Costs or Renewable Avoided Costs in effect at the time the agreement is executed. Avoided Costs are defined in 18 CFR 292.101(6) as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."

Monthly On-Peak prices are included in both the Standard Avoided Costs as listed in Tables 1a, 2a, and 3a and Renewable Avoided Costs as listed in Tables 4a, 5a, and 6a. Monthly Off-Peak prices are included in both the Standard Avoided Costs as listed in Tables 1b, 2b, and 3b and Renewable Avoided Costs as listed in Tables 4b, 5b, and 6b.

ON-PEAK PERIOD

The On-Peak period is 6:00 a.m. until 10:00 p.m., Monday through Saturday.

OFF-PEAK PERIOD

The Off-Peak period is 10:00 p.m. until 6:00 a.m., Monday through Saturday, and all day on Sunday.

Standard Avoided Costs are based on forward market price estimates through the Resource Sufficiency Period, the period of time during which the Company's Standard Avoided Costs are associated with incremental purchases of Energy and capacity from the market. For the Resource Deficiency Period, the Standard Avoided Costs reflect the fully allocated costs of a natural gas fueled combined cycle combustion turbine (CCCT) including fuel and capital costs. The CCCT Avoided Costs are based on the variable cost of Energy plus capitalized Energy costs at a 93% capacity factor based on a natural gas price forecast, with prices modified for shrinkage and transportation costs.

Renewable Avoided Costs are based on forward market price estimates through the Renewable Resource Sufficiency Period, the period of time during which the Company's Renewable Avoided Costs are associated with incremental purchases of energy and capacity from the market. For the Renewable Resource Deficiency Period, the Renewable Avoided Costs reflect the fully allocated costs of a wind plant including capital costs.

PRICING FOR STANDARD PPA

Pricing represents the purchase price per MWh the Company will pay for electricity delivered to a Point of Delivery (POD) within the Company's service territory pursuant to a Standard PPA up to the nameplate rating of the QF in any hour. Any Energy delivered in excess of the nameplate rating will be purchased at the applicable Off-Peak Prices for the selected pricing option.

The Standard PPA pricing will be based on either the Standard or Renewable Avoided Costs in effect at the time the agreement is executed.

The Company will pay the Seller either the Off-Peak Standard Avoided Cost pursuant to Tables 1b, 2b, or 3b or the Off-Peak Renewable Avoided Costs pursuant to Tables 4b, 5b, or 6b for: (a) all Net Output delivered prior to the Commercial Operation Date; (b) all Net Output deliveries greater than Maximum Net Output in any PPA year; (c) any generation subject to and as adjusted by the provisions of Section 4.3 of the Standard PPA; (d) Net Output delivered in the Off-Peak Period; and (e) deliveries above the nameplate capacity in any hour. The Company will pay the Seller either the On-Peak Standard Avoided Cost pursuant to Tables 1a, 2a, or 3a or the On-Peak Renewable Avoided Costs pursuant to Tables 4a, 5a, or 6a for all other Net Output. (See the PPA for defined terms.)

1) Standard Fixed Price Option

The Standard Fixed Price Option is based on Standard Avoided Costs including forecasted natural gas prices. It is available to all QFs.

This option is available for a maximum term of 15 years. Prices will be as established at the time the Standard PPA is executed and will be equal to the Standard Avoided Costs in Tables 1a and 1b, 2a and 2b, or 3a and 3c, depending on the type of QF, effective at execution. QFs using any resource type other than wind and solar are assumed to be Base Load QFs.

Prices paid to the Seller under the Standard Fixed Price Option include adjustments for the capacity contribution of the QF resource type relative to that of the avoided proxy resource. Both the Base Load QF resources (Tables 1a and 1b) and the avoided proxy resource, the basis used to determine Standard Avoided Costs for the Standard Fixed Price Option, are assumed to have a capacity contribution to peak of 100%. The capacity contribution for Wind QF resources (Tables 2a and 2b) is assumed to be 5%. The capacity contribution for Solar QF resources (Tables 3a and 3b) is assumed to be 5%.

Prices paid to the Seller under the Standard Fixed Price Option for Wind QFs (Tables 2a and 2b) include a reduction for the wind integration costs in Table 7. However, if the Wind QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the wind integration charges in Table 7, in addition to the prices listed in Tables 2a and 2b, for a net-zero effect.

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

Sellers with PPAs exceeding 15 years will receive pricing equal to the Mid-C Index Price for all years up to five in excess of the initial 15.

					T.	ABLE 1a						
					Avo	ided Cos	ts					
			St	andard F	ixed Pric	e Option	for Base	Load QF	•			
				0	n-Peak F	orecast (\$/MWH)					
				-				_	_			_
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	28.21	22.46	15.61	14.71	12.46	16.96	23.96	26.96	24.96	23.71	26.71	31.46
2017	29.96	28.21	24.71	20.96	19.46	20.46	27.96	30.96	29.46	27.71	28.71	33.71
2018	31.71	31.11	28.11	22.13	21.28	21.28	29.93	33.37	30.63	28.61	31.86	35.71
2019	33.94	31.95	27.97	23.70	22.00	23.13	31.67	35.08	33.37	31.38	32.52	38.21
2020	35.74	33.64	29.45	24.95	23.15	24.35	33.34	36.94	35.14	33.04	34.24	40.24
2021	67.43	67.34	65.41	64.69	64.41	64.50	64.61	64.73	64.84	65.48	68.60	68.72
2022	69.01	68.84	68.08	67.13	66.81	66.91	67.04	67.17	67.29	67.83	71.38	71.70
2023	71.95	71.76	70.39	69.19	69.07	69.18	69.31	69.45	69.58	70.12	73.56	73.70
2024	74.17	73.85	72.67	71.29	71.10	71.21	71.35	71.50	71.63	72.20	76.49	76.64
2025	77.19	77.30	75.84	74.88	75.02	75.14	75.30	75.47	75.62	75.80	82.57	82.89
2026	85.18	85.30	82.77	81.28	81.22	81.36	81.56	81.74	81.90	82.36	89.02	88.72
2027	86.85	86.76	85.14	83.12	82.89	83.03	83.00	83.32	83.46	83.97	91.39	91.15
2028	89.32	89.31	87.96	85.46	85.30	85.46	85.31	85.64	85.95	86.65	94.66	93.55
2029	94.06	93.99	91.23	88.74	87.97	88.15	87.71	88.06	88.61	89.34	98.37	98.11
2030	97.60	97.54	94.87	92.62	92.40	92.57	92.61	93.00	93.12	93.68	102.42	102.70
2031	99.56	99.50	96.78	94.48	94.26	94.43	94.47	94.87	94.99	95.56	104.47	104.76
2032	103.85	103.80	100.57	98.18	97.96	98.15	98.23	98.65	98.76	99.36	108.86	109.41
2033	106.56	106.51	103.17	100.72	100.50	100.69	100.78	101.21	101.32	101.93	111.67	112.26
2034	109.12	109.07	105.60	103.10	102.88	103.08	103.17	103.61	103.72	104.35	114.33	114.96
2035	111.55	111.51	107.91	105.35	105.12	105.33	105.43	105.89	105.99	106.63	116.87	117.54
2036	113.85	113.80	110.14	107.53	107.30	107.51	107.60	108.07	108.18	108.83	119.27	119.95
2037	116.50	116.45	112.72	110.06	109.82	110.04	110.14	110.61	110.73	111.39	122.03	122.73
2038	119.08	119.03	115.22	112.51	112.27	112.49	112.59	113.08	113.19	113.87	124.71	125.42
2039	121.47	121.42	117.54	114.77	114.53	114.75	114.85	115.35	115.47	116.15	127.21	127.93
2040	124.25	124.20	120.25	117.43	117.18	117.41	117.51	118.02	118.14	118.84	130.10	130.85
2041	126.72	126.67	122.64	119.76	119.51	119.74	119.85	120.36	120.49	121.20	132.68	133.44

					Т/	ABLE 1b						
						ided Cost	ts					
			Sta	andard F	ixed Pric	e Option	for Base	Load QF				
				0	ff-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	25.61	20.71	13.96	11.41	6.31	10.11	15.71	20.96	20.96	21.21	23.46	26.71
2017	25.71	24.21	22.21	15.71	13.71	12.71	19.71	25.21	25.46	24.71	25.71	27.96
2018	26.17	28.12	25.56	19.46	14.68	12.54	19.71	27.04	26.93	25.35	28.20	30.62
2019	29.84	28.09	25.75	18.15	15.81	14.64	22.83	29.26	29.55	28.67	29.84	32.47
2020	31.75	29.88	27.38	19.28	16.79	15.54	24.27	31.12	31.43	30.50	31.75	34.55
2021	28.88	28.79	26.86	26.15	25.87	25.95	26.07	26.19	26.30	26.94	30.06	30.18
2022	29.73	29.56	28.79	27.85	27.53	27.63	27.75	27.88	28.00	28.54	32.09	32.42
2023	31.78	31.59	30.21	29.01	28.90	29.00	29.14	29.27	29.40	29.95	33.38	33.52
2024	33.48	33.16	31.98	30.60	30.41	30.52	30.66	30.81	30.95	31.51	35.80	35.96
2025	35.58	35.69	34.24	33.27	33.42	33.53	33.70	33.86	34.01	34.19	40.97	41.28
2026	42.77	42.89	40.36	38.87	38.81	38.95	39.15	39.34	39.50	39.95	46.62	46.31
2027	43.63	43.54	41.91	39.89	39.66	39.80	39.77	40.09	40.24	40.74	48.16	47.92
2028	45.26	45.25	43.90	41.40	41.23	41.40	41.25	41.58	41.89	42.59	50.60	49.48
2029	49.15	49.08	46.32	43.83	43.06	43.24	42.80	43.15	43.70	44.43	53.46	53.20
2030	51.82	51.76	49.09	46.84	46.62	46.79	46.83	47.22	47.34	47.90	56.64	56.92
2031	52.90	52.84	50.11	47.82	47.59	47.77	47.81	48.21	48.33	48.90	57.81	58.10
2032	56.59	56.54	53.31	50.92	50.70	50.89	50.97	51.39	51.50	52.10	61.60	62.15
2033	58.08	58.03	54.69	52.24	52.02	52.21	52.30	52.73	52.84	53.45	63.19	63.78
2034	59.54	59.50	56.03	53.52	53.30	53.50	53.59	54.04	54.15	54.77	64.76	65.39
2035	61.18	61.14	57.54	54.98	54.75	54.96	55.06	55.52	55.62	56.26	66.50	67.17
2036	62.67	62.62	58.96	56.35	56.12	56.33	56.43	56.89	57.00	57.65	68.09	68.78
2037	64.17	64.12	60.39	57.73	57.49	57.71	57.80	58.28	58.39	59.06	69.69	70.39
2038	65.73	65.69	61.88	59.17	58.93	59.15	59.25	59.73	59.85	60.52	71.37	72.08
2039	67.09	67.04	63.16	60.40	60.15	60.38	60.48	60.98	61.09	61.78	72.83	73.56
2040	68.83	68.78	64.83	62.01	61.76	61.99	62.09	62.60	62.72	63.42	74.68	75.42
2041	70.23	70.17	66.14	63.27	63.02	63.25	63.36	63.87	63.99	64.71	76.19	76.95

					T/	ABLE 2a						
					Avoi	ded Cos	ts					
				Standard	Fixed P	rice Optic	on for Wi	nd QF				
				0	n-Peak F	orecast (\$/MW H)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	24.37	18.62	11.77	10.87	8.62	13.12	20.12	23.12	21.12	19.87	22.87	27.62
2017	26.05	24.30	20.80	17.05	15.55	16.55	24.05	27.05	25.55	23.80	24.80	29.80
2018	27.72	27.12	24.12	18.14	17.29	17.29	25.94	29.38	26.64	24.62	27.87	31.72
2019	29.87	27.88	23.90	19.63	17.93	19.06	27.60	31.01	29.30	27.31	28.45	34.14
2020	31.59	29.49	25.30	20.80	19.00	20.20	29.19	32.79	30.99	28.89	30.09	36.09
2021	30.68	30.59	28.66	27.94	27.66	27.75	27.87	27.99	28.10	28.74	31.86	31.98
2022	31.56	31.39	30.62	29.68	29.36	29.46	29.59	29.72	29.84	30.38	33.93	34.25
2023	33.67	33.48	32.11	30.91	30.79	30.90	31.03	31.17	31.30	31.84	35.28	35.42
2024	35.38	35.06	33.88	32.49	32.30	32.42	32.56	32.70	32.84	33.40	37.70	37.85
2025	37.53	37.64	36.18	35.22	35.36	35.48	35.64	35.81	35.96	36.14	42.91	43.23
2026	44.75	44.87	42.35	40.86	40.79	40.94	41.13	41.32	41.48	41.94	48.60	48.29
2027	45.65	45.56	43.93	41.91	41.68	41.82	41.79	42.12	42.26	42.76	50.18	49.94
2028	47.32	47.31	45.96	43.46	43.30	43.46	43.31	43.64	43.95	44.65	52.66	51.55
2029	51.25	51.18	48.43	45.94	45.16	45.34	44.90	45.25	45.80	46.53	55.57	55.30
2030	53.96	53.90	51.23	48.98	48.76	48.93	48.97	49.36	49.48	50.04	58.78	59.06
2031	55.08	55.02	52.29	50.00	49.77	49.95	49.99	50.38	50.51	51.08	59.99	60.28
2032	58.77	58.72	55.49	53.10	52.88	53.07	53.15	53.57	53.68	54.28	63.78	64.33
2033	60.35	60.30	56.96	54.51	54.29	54.49	54.57	55.00	55.11	55.72	65.46	66.05
2034	61.88	61.83	58.36	55.86	55.63	55.84	55.93	56.37	56.48	57.10	67.09	67.72
2035	63.54	63.49	59.90	57.34	57.11	57.32	57.42	57.87	57.98	58.62	68.86	69.53
2036	65.04	65.00	61.33	58.72	58.49	58.70	58.80	59.27	59.38	60.03	70.46	71.15
2037	66.61	66.57	62.83	60.17	59.93	60.15	60.25	60.73	60.84	61.50	72.14	72.84
2038	68.23	68.18	64.37	61.66	61.42	61.64	61.74	62.23	62.34	63.02	73.86	74.57
2039	69.64	69.59	65.71	62.94	62.70	62.92	63.03	63.52	63.64	64.33	75.38	76.11
2040	71.42	71.37	67.41	64.60	64.35	64.58	64.68	65.18	65.30	66.00	77.27	78.01
2041	72.87	72.82	68.79	65.92	65.66	65.90	66.00	66.52	66.64	67.35	78.84	79.59

					T	ABLE 2b						
					Avo	ded Cos	s					
				Standard	I Fixed P	rice Optic	on for Wi	nd QF				
				0	ff-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	21.77	16.87	10.12	7.57	2.47	6.27	11.87	17.12	17.12	17.37	19.62	22.87
2017	21.80	20.30	18.30	11.80	9.80	8.80	15.80	21.30	21.55	20.80	21.80	24.05
2018	22.18	24.13	21.57	15.47	10.69	8.55	15.72	23.05	22.94	21.36	24.21	26.63
2019	25.77	24.02	21.68	14.08	11.74	10.57	18.76	25.19	25.48	24.60	25.77	28.40
2020	27.60	25.73	23.23	15.13	12.64	11.39	20.12	26.97	27.28	26.35	27.60	30.40
2021	24.65	24.56	22.63	21.92	21.64	21.72	21.84	21.96	22.07	22.71	25.83	25.95
2022	25.42	25.25	24.48	23.54	23.22	23.32	23.44	23.57	23.69	24.23	27.78	28.11
2023	27.39	27.20	25.82	24.62	24.51	24.61	24.75	24.88	25.01	25.56	28.99	29.13
2024	29.01	28.69	27.51	26.13	25.94	26.05	26.19	26.34	26.48	27.04	31.33	31.49
2025	31.02	31.13	29.68	28.71	28.86	28.97	29.14	29.30	29.45	29.63	36.41	36.72
2026	38.12	38.24	35.71	34.22	34.16	34.30	34.50	34.69	34.85	35.30	41.97	41.66
2027	38.89	38.80	37.17	35.15	34.92	35.06	35.03	35.35	35.50	36.00	43.42	43.18
2028	40.43	40.42	39.07	36.57	36.40	36.57	36.42	36.75	37.06	37.76	45.77	44.65
2029	44.23	44.16	41.40	38.91	38.14	38.32	37.88	38.23	38.78	39.51	48.54	48.28
2030	46.80	46.74	44.07	41.82	41.60	41.77	41.81	42.20	42.32	42.88	51.62	51.90
2031	47.78	47.72	44.99	42.70	42.47	42.65	42.69	43.09	43.21	43.78	52.69	52.98
2032	51.38	51.33	48.10	45.71	45.49	45.68	45.76	46.18	46.29	46.89	56.39	56.94
2033	52.77	52.72	49.38	46.93	46.71	46.90	46.99	47.42	47.53	48.14	57.88	58.47
2034	54.12	54.08	50.61	48.10	47.88	48.08	48.17	48.62	48.73	49.35	59.34	59.97
2035	55.66	55.62	52.02	49.46	49.23	49.44	49.54	50.00	50.10	50.74	60.98	61.65
2036	57.04	56.99	53.33	50.72	50.49	50.70	50.80	51.26	51.37	52.02	62.46	63.15
2037	58.43	58.38	54.65	51.99	51.75	51.97	52.06	52.54	52.65	53.32	63.95	64.65
2038	59.88	59.84	56.03	53.32	53.08	53.30	53.40	53.88	54.00	54.67	65.52	66.23
2039	61.13	61.08	57.20	54.44	54.19	54.42	54.52	55.02	55.13	55.82	66.87	67.60
2040	62.75	62.70	58.75	55.93	55.68	55.91	56.01	56.52	56.64	57.34	68.60	69.34
2041	64.04	63.98	59.95	57.08	56.83	57.06	57.17	57.68	57.80	58.52	70.00	70.76

					T	ABLE 3a						
					Avoi	ded Cos	ts					
				Standard	I Fixed P	rice Optic	on for So	lar QF				
				0	n-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	28.21	22.46	15.61	14.71	12.46	16.96	23.96	26.96	24.96	23.71	26.71	31.46
2017	29.96	28.21	24.71	20.96	19.46	20.46	27.96	30.96	29.46	27.71	28.71	33.71
2018	31.71	31.11	28.11	22.13	21.28	21.28	29.93	33.37	30.63	28.61	31.86	35.71
2019	33.94	31.95	27.97	23.70	22.00	23.13	31.67	35.08	33.37	31.38	32.52	38.21
2020	35.74	33.64	29.45	24.95	23.15	24.35	33.34	36.94	35.14	33.04	34.24	40.24
2021	33.98	33.89	31.96	31.24	30.96	31.05	31.16	31.28	31.39	32.03	35.15	35.27
2022	34.92	34.75	33.98	33.04	32.72	32.82	32.94	33.08	33.20	33.74	37.28	37.61
2023	37.09	36.90	35.52	34.32	34.21	34.31	34.44	34.58	34.71	35.26	38.69	38.83
2024	38.86	38.54	37.36	35.98	35.79	35.90	36.04	36.19	36.32	36.88	41.18	41.33
2025	41.08	41.19	39.73	38.77	38.92	39.03	39.19	39.36	39.51	39.69	46.46	46.78
2026	48.37	48.49	45.97	44.48	44.42	44.56	44.75	44.94	45.10	45.56	52.22	51.91
2027	49.34	49.25	47.62	45.61	45.38	45.51	45.48	45.81	45.95	46.45	53.87	53.63
2028	51.08	51.07	49.72	47.22	47.06	47.22	47.07	47.40	47.72	48.41	56.42	55.31
2029	55.08	55.01	52.26	49.77	48.99	49.17	48.73	49.08	49.63	50.36	59.40	59.13
2030	57.87	57.81	55.14	52.89	52.67	52.84	52.88	53.27	53.39	53.95	62.69	62.97
2031	59.07	59.00	56.28	53.98	53.76	53.93	53.98	54.37	54.49	55.06	63.98	64.26
2032	62.83	62.78	59.56	57.16	56.94	57.13	57.21	57.64	57.75	58.34	67.85	68.39
2033	64.49	64.44	61.09	58.64	58.42	58.62	58.70	59.14	59.25	59.86	69.60	70.18
2034	66.10	66.05	62.58	60.08	59.85	60.05	60.14	60.59	60.70	61.32	71.31	71.94
2035	67.84	67.79	64.20	61.64	61.41	61.62	61.71	62.17	62.28	62.92	73.16	73.83
2036	69.43	69.38	65.72	63.11	62.88	63.09	63.19	63.66	63.77	64.42	74.85	75.54
2037	71.08	71.04	67.30	64.64	64.40	64.62	64.72	65.20	65.31	65.97	76.61	77.31
2038	72.78	72.73	68.93	66.22	65.98	66.20	66.30	66.78	66.90	67.57	78.42	79.13
2039	74.28	74.23	70.35	67.58	67.34	67.56	67.67	68.16	68.28	68.97	80.02	80.75
2040	76.15	76.10	72.15	69.33	69.08	69.31	69.42	69.92	70.04	70.74	82.01	82.75
2041	77.69	77.64	73.61	70.74	70.48	70.72	70.82	71.34	71.46	72.17	83.66	84.41

					T	ABLE 3b						
					Avo	ided Cost	ts					
				Standard	I Fixed P	rice Optic	on for So	lar QF				
				0	ff-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	25.61	20.71	13.96	11.41	6.31	10.11	15.71	20.96	20.96	21.21	23.46	26.71
2017	25.71	24.21	22.21	15.71	13.71	12.71	19.71	25.21	25.46	24.71	25.71	27.96
2018	26.17	28.12	25.56	19.46	14.68	12.54	19.71	27.04	26.93	25.35	28.20	30.62
2019	29.84	28.09	25.75	18.15	15.81	14.64	22.83	29.26	29.55	28.67	29.84	32.47
2020	31.75	29.88	27.38	19.28	16.79	15.54	24.27	31.12	31.43	30.50	31.75	34.55
2021	28.88	28.79	26.86	26.15	25.87	25.95	26.07	26.19	26.30	26.94	30.06	30.18
2022	29.73	29.56	28.79	27.85	27.53	27.63	27.75	27.88	28.00	28.54	32.09	32.42
2023	31.78	31.59	30.21	29.01	28.90	29.00	29.14	29.27	29.40	29.95	33.38	33.52
2024	33.48	33.16	31.98	30.60	30.41	30.52	30.66	30.81	30.95	31.51	35.80	35.96
2025	35.58	35.69	34.24	33.27	33.42	33.53	33.70	33.86	34.01	34.19	40.97	41.28
2026	42.77	42.89	40.36	38.87	38.81	38.95	39.15	39.34	39.50	39.95	46.62	46.31
2027	43.63	43.54	41.91	39.89	39.66	39.80	39.77	40.09	40.24	40.74	48.16	47.92
2028	45.26	45.25	43.90	41.40	41.23	41.40	41.25	41.58	41.89	42.59	50.60	49.48
2029	49.15	49.08	46.32	43.83	43.06	43.24	42.80	43.15	43.70	44.43	53.46	53.20
2030	51.82	51.76	49.09	46.84	46.62	46.79	46.83	47.22	47.34	47.90	56.64	56.92
2031	52.90	52.84	50.11	47.82	47.59	47.77	47.81	48.21	48.33	48.90	57.81	58.10
2032	56.59	56.54	53.31	50.92	50.70	50.89	50.97	51.39	51.50	52.10	61.60	62.15
2033	58.08	58.03	54.69	52.24	52.02	52.21	52.30	52.73	52.84	53.45	63.19	63.78
2034	59.54	59.50	56.03	53.52	53.30	53.50	53.59	54.04	54.15	54.77	64.76	65.39
2035	61.18	61.14	57.54	54.98	54.75	54.96	55.06	55.52	55.62	56.26	66.50	67.17
2036	62.67	62.62	58.96	56.35	56.12	56.33	56.43	56.89	57.00	57.65	68.09	68.78
2037	64.17	64.12	60.39	57.73	57.49	57.71	57.80	58.28	58.39	59.06	69.69	70.39
2038	65.73	65.69	61.88	59.17	58.93	59.15	59.25	59.73	59.85	60.52	71.37	72.08
2039	67.09	67.04	63.16	60.40	60.15	60.38	60.48	60.98	61.09	61.78	72.83	73.56
2040	68.83	68.78	64.83	62.01	61.76	61.99	62.09	62.60	62.72	63.42	74.68	75.42
2041	70.23	70.17	66.14	63.27	63.02	63.25	63.36	63.87	63.99	64.71	76.19	76.95

PRICING OPTIONS FOR STANDARD PPA (Continued)

2) Renewable Fixed Price Option

The Renewable Fixed Price Option is based on Renewable Avoided Costs. It is available only to Renewable QFs that generate electricity from a renewable energy source that may be used by the Company to comply with the Oregon Renewable Portfolio Standard as set forth in ORS 469A.005 to 469A.210.

This option is available for a maximum term of 15 years. Prices will be as established at the time the Standard PPA is executed and will be equal to the Renewable Avoided Costs in Tables 4a and 4b, 5a and 5b, or 6a and 6b, depending on the type of QF, effective at execution. QFs using any resource type other than wind and solar are assumed to be Base Load QFs.

Sellers will retain all Environmental Attributes generated by the facility during the Renewable Resource Sufficiency Period. A Renewable QF choosing the Renewable Fixed Price Option must cede all RPS Attributes generated by the facility to the Company from the start of the Renewable Resource Deficiency Period through the remainder of the PPA term.

Prices paid to the Seller under the Renewable Fixed Price Option include adjustments for the capacity contribution of the QF resource type relative to that of the avoided proxy resource. Both Wind QF resources (Tables 5a and 5b) and the avoided proxy resource, the basis used to determine Renewable Avoided Costs for the Renewable Fixed Price Option, are assumed to have a capacity contribution to peak of 5%. The capacity contribution for Solar QF resources (Tables 6a and 6b) is assumed to be 5%. The capacity contribution for Base Load QF resources (Tables 4a and 4b) is assumed to be 100%.

The Renewable Avoided Costs during the Renewable Resource Deficiency Period reflect an increase for avoided wind integration costs, shown in Table 7.

Prices paid to the Seller under the Renewable Fixed Price Option for Wind QFs (Tables 5a and 5b) include a reduction for the wind integration costs in Table 7, which cancels out wind integration costs included in the Renewable Avoided Costs during the Renewable Resource Deficiency Period. However, if the Wind QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the wind integration charges in Table 7, in addition to the prices listed in Tables 5a and 5b.

Sellers with PPAs exceeding 15 years will receive pricing equal to the Mid-C Index Price for all years up to five in excess of the initial 15.

					T	ABLE 4a						
				F	Renewabl	e Avoide	d Costs					
			Rer	newable l	ixed Price	ce Option	for Base	e Load Q	F			
				0	n-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	28.36	22.61	15.76	14.86	12.61	17.11	24.11	27.11	25.11	23.86	26.86	31.61
2017	30.11	28.36	24.86	21.11	19.61	20.61	28.11	31.11	29.61	27.86	28.86	33.86
2018	31.86	31.26	28.26	22.28	21.43	21.43	30.08	33.52	30.78	28.76	32.01	35.86
2019	34.10	32.11	28.13	23.86	22.16	23.29	31.83	35.24	33.53	31.54	32.68	38.37
2020	115.34	115.32	114.56	115.02	118.22	117.33	117.01	116.89	115.60	114.63	115.47	114.45
2021	117.94	118.18	116.67	117.75	120.59	119.83	119.26	119.77	118.26	117.25	118.55	117.22
2022	120.48	120.36	118.46	120.19	123.17	122.14	121.69	121.65	120.55	119.55	120.98	119.53
2023	123.26	122.83	120.85	122.92	125.37	124.64	124.29	123.92	123.08	121.92	123.63	122.53
2024	124.86	125.01	123.06	125.07	127.80	126.78	126.67	126.41	126.22	123.83	124.83	124.96
2025	127.73	128.05	125.86	128.21	131.66	130.48	129.53	129.66	128.84	126.59	127.76	127.41
2026	130.91	130.58	129.12	131.30	135.76	132.28	132.28	132.69	132.40	129.34	131.17	130.23
2027	133.47	133.03	131.38	133.50	139.48	134.88	134.51	135.95	134.79	131.96	133.26	132.78
2028	135.95	134.91	132.89	136.24	141.79	136.93	137.64	137.65	136.77	134.76	135.84	135.06
2029	138.81	138.57	135.91	139.29	149.30	140.74	140.82	140.82	140.86	137.50	138.32	138.21
2030	141.68	141.39	139.11	142.00	153.18	145.20	143.05	142.93	144.31	140.18	140.75	140.79
2031	144.29	143.79	142.17	145.52	156.10	149.27	145.71	146.65	146.86	143.04	144.15	143.71
2032	146.51	146.00	144.35	147.76	158.51	151.58	147.95	148.91	149.13	145.24	146.37	145.92
2033	149.91	149.40	147.71	151.19	162.18	155.09	151.39	152.37	152.59	148.62	149.77	149.31
2034	152.96	152.43	150.71	154.26	165.46	158.24	154.46	155.46	155.68	151.64	152.81	152.35
2035	155.76	155.22	153.46	157.08	168.50	161.14	157.29	158.31	158.54	154.41	155.60	155.13
2036	158.31	157.76	155.97	159.65	171.26	163.78	159.86	160.90	161.13	156.94	158.15	157.67
2037	161.83	161.27	159.44	163.20	175.07	167.42	163.42	164.48	164.71	160.43	161.67	161.18
2038	164.95	164.38	162.52	166.35	178.45	170.65	166.57	167.65	167.89	163.52	164.79	164.29
2039	168.13	167.55	165.66	169.56	181.89	173.94	169.79	170.89	171.13	166.68	167.97	167.46
2040	171.05	170.46	168.54	172.51	185.04	176.96	172.74	173.85	174.10	169.58	170.89	170.37
2041	174.69	174.08	172.11	176.17	188.98	180.72	176.40	177.55	177.80	173.18	174.52	173.99

					T	ABLE 4b						
				R	enewable	e Avoide	d Costs					
			Rer	newable F	ixed Pric	e Option	for Base	Load QI	F			
				0	ff-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	25.76	20.86	14.11	11.56	6.46	10.26	15.86	21.11	21.11	21.36	23.61	26.86
2017	25.86	24.36	22.36	15.86	13.86	12.86	19.86	25.36	25.61	24.86	25.86	28.11
2018	26.32	28.27	25.71	19.61	14.83	12.69	19.86	27.19	27.08	25.50	28.35	30.77
2019	30.00	28.25	25.91	18.31	15.97	14.80	22.99	29.42	29.71	28.83	30.00	32.63
2020	62.76	63.02	64.56	63.31	59.92	60.16	60.45	61.61	62.52	63.74	63.55	63.99
2021	64.93	64.15	65.85	64.48	61.58	61.62	62.27	62.62	63.78	65.82	63.38	65.09
2022	65.85	65.52	67.77	65.49	62.45	62.82	64.33	63.35	65.00	67.04	64.42	66.29
2023	66.70	66.75	69.10	67.28	62.84	64.01	65.40	64.85	66.14	68.41	65.38	67.63
2024	67.25	67.31	70.47	67.09	63.18	65.92	64.75	65.12	66.62	68.68	67.42	68.05
2025	68.62	68.60	71.94	68.08	63.17	66.28	66.12	67.12	67.23	70.19	69.68	69.06
2026	68.95	69.85	72.28	68.56	63.85	67.22	67.05	67.75	67.05	71.12	69.85	69.89
2027	71.31	71.29	73.13	70.34	63.69	68.45	68.79	68.16	68.57	73.22	70.67	71.18
2028	72.28	72.90	75.41	72.10	63.09	69.98	70.15	68.82	70.20	73.79	71.48	73.41
2029	72.78	73.60	76.79	73.50	58.25	70.29	71.37	70.00	71.53	74.58	73.61	74.68
2030	73.91	74.82	78.36	73.64	58.00	70.89	72.02	72.19	72.00	75.99	75.36	76.23
2031	75.51	76.70	79.40	74.00	59.17	70.67	73.55	73.71	72.16	77.24	77.07	76.31
2032	76.76	77.97	80.71	75.23	60.15	71.83	74.76	74.93	73.35	78.52	78.34	77.57
2033	78.46	79.69	82.50	76.89	61.48	73.42	76.42	76.58	74.97	80.25	80.07	79.29
2034	79.97	81.23	84.09	78.37	62.66	74.84	77.89	78.06	76.42	81.80	81.62	80.82
2035	81.52	82.80	85.71	79.88	63.87	76.28	79.39	79.57	77.89	83.38	83.19	82.38
2036	82.86	84.17	87.13	81.20	64.93	77.54	80.70	80.88	79.18	84.76	84.57	83.74
2037	84.69	86.03	89.05	83.00	66.36	79.25	82.49	82.67	80.93	86.63	86.44	85.59
2038	86.33	87.69	90.77	84.60	67.64	80.78	84.08	84.26	82.49	88.30	88.11	87.24
2039	87.99	89.38	92.52	86.23	68.95	82.34	85.70	85.89	84.08	90.01	89.81	88.92
2040	89.45	90.85	94.05	87.66	70.09	83.70	87.12	87.31	85.47	91.49	91.29	90.39
2041	91.42	92.86	96.13	89.59	71.63	85.55	89.04	89.24	87.36	93.51	93.31	92.39

					T.	ABLE 5a						
				F	Renewabl	e Avoide	d Costs					
			F	Renewab	le Fixed F	Price Opt	ion for W	ind QF				
				0	n-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	24.52	18.77	11.92	11.02	8.77	13.27	20.27	23.27	21.27	20.02	23.02	27.77
2017	26.20	24.45	20.95	17.20	15.70	16.70	24.20	27.20	25.70	23.95	24.95	29.95
2018	27.87	27.27	24.27	18.29	17.44	17.44	26.09	29.53	26.79	24.77	28.02	31.87
2019	30.03	28.04	24.06	19.79	18.09	19.22	27.76	31.17	29.46	27.47	28.61	34.30
2020	75.38	75.37	74.61	75.06	78.26	77.37	77.05	76.93	75.64	74.67	75.51	74.49
2021	77.10	77.33	75.83	76.90	79.75	78.99	78.41	78.92	77.41	76.40	77.70	76.38
2022	78.85	78.72	76.82	78.56	81.53	80.51	80.05	80.02	78.92	77.92	79.34	77.90
2023	80.71	80.27	78.29	80.37	82.82	82.08	81.73	81.37	80.53	79.36	81.08	79.97
2024	81.74	81.89	79.93	81.95	84.68	83.66	83.55	83.28	83.10	80.71	81.71	81.84
2025	83.64	83.97	81.78	84.13	87.57	86.40	85.44	85.57	84.75	82.51	83.68	83.32
2026	85.97	85.64	84.18	86.37	90.82	87.34	87.34	87.75	87.46	84.40	86.23	85.29
2027	87.67	87.23	85.57	87.69	93.67	89.07	88.71	90.15	88.99	86.16	87.45	86.98
2028	89.26	88.22	86.20	89.55	95.10	90.24	90.95	90.96	90.08	88.07	89.15	88.37
2029	91.22	90.98	88.32	91.70	101.72	93.16	93.23	93.23	93.28	89.92	90.73	90.62
2030	93.17	92.88	90.60	93.49	104.67	96.69	94.54	94.42	95.80	91.67	92.24	92.28
2031	94.84	94.34	92.72	96.07	106.65	99.82	96.26	97.20	97.42	93.59	94.70	94.26
2032	96.40	95.90	94.24	97.65	108.40	101.47	97.85	98.80	99.02	95.13	96.26	95.82
2033	98.55	98.03	96.34	99.82	110.81	103.72	100.02	101.00	101.22	97.25	98.40	97.95
2034	100.44	99.91	98.19	101.74	112.94	105.72	101.94	102.94	103.17	99.12	100.29	99.83
2035	102.38	101.85	100.09	103.71	115.13	107.76	103.92	104.93	105.16	101.04	102.23	101.76
2036	104.06	103.51	101.72	105.40	117.01	109.53	105.61	106.65	106.88	102.69	103.90	103.42
2037	106.37	105.81	103.99	107.74	119.61	111.96	107.96	109.02	109.26	104.97	106.21	105.72
2038	108.42	107.86	105.99	109.82	121.92	114.12	110.05	111.12	111.37	107.00	108.26	107.76
2039	110.52	109.94	108.04	111.95	124.27	116.33	112.17	113.27	113.52	109.07	110.36	109.85
2040	112.32	111.73	109.81	113.77	126.31	118.23	114.00	115.12	115.37	110.85	112.16	111.64
2041	114.83	114.23	112.26	116.31	129.12	120.86	116.55	117.69	117.95	113.32	114.66	114.13

					T	ABLE 5b						
				R	enewabl	e Avoide	d Costs					
			F	Renewabl	e Fixed F	Price Opt	ion for W	ind QF				
				0	ff-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	21.92	17.02	10.27	7.72	2.62	6.42	12.02	17.27	17.27	17.52	19.77	23.02
2017	21.95	20.45	18.45	11.95	9.95	8.95	15.95	21.45	21.70	20.95	21.95	24.20
2018	22.33	24.28	21.72	15.62	10.84	8.70	15.87	23.20	23.09	21.51	24.36	26.78
2019	25.93	24.18	21.84	14.24	11.90	10.73	18.92	25.35	25.64	24.76	25.93	28.56
2020	58.61	58.87	60.41	59.16	55.77	56.01	56.30	57.46	58.37	59.59	59.40	59.84
2021	60.70	59.92	61.62	60.25	57.35	57.39	58.04	58.39	59.55	61.59	59.15	60.86
2022	61.54	61.21	63.46	61.18	58.14	58.51	60.02	59.04	60.69	62.73	60.11	61.98
2023	62.31	62.36	64.71	62.89	58.45	59.62	61.01	60.46	61.75	64.02	60.99	63.24
2024	62.78	62.84	66.00	62.62	58.71	61.45	60.28	60.65	62.15	64.21	62.95	63.58
2025	64.06	64.04	67.38	63.52	58.61	61.72	61.56	62.56	62.67	65.63	65.12	64.50
2026	64.30	65.20	67.63	63.91	59.20	62.57	62.40	63.10	62.40	66.47	65.20	65.24
2027	66.57	66.55	68.39	65.60	58.95	63.71	64.05	63.42	63.83	68.48	65.93	66.44
2028	67.45	68.07	70.58	67.27	58.26	65.15	65.32	63.99	65.37	68.96	66.65	68.58
2029	67.86	68.68	71.87	68.58	53.33	65.37	66.45	65.08	66.61	69.66	68.69	69.76
2030	68.89	69.80	73.34	68.62	52.98	65.87	67.00	67.17	66.98	70.97	70.34	71.21
2031	70.39	71.58	74.28	68.88	54.05	65.55	68.43	68.59	67.04	72.12	71.95	71.19
2032	71.55	72.76	75.50	70.02	54.94	66.62	69.55	69.72	68.14	73.31	73.13	72.36
2033	73.15	74.38	77.19	71.58	56.17	68.11	71.11	71.27	69.66	74.94	74.76	73.98
2034	74.55	75.81	78.67	72.95	57.24	69.42	72.47	72.64	71.00	76.38	76.20	75.40
2035	76.00	77.28	80.19	74.36	58.35	70.76	73.87	74.05	72.37	77.86	77.67	76.86
2036	77.23	78.54	81.50	75.57	59.30	71.91	75.07	75.25	73.55	79.13	78.94	78.11
2037	78.95	80.29	83.31	77.26	60.62	73.51	76.75	76.93	75.19	80.89	80.70	79.85
2038	80.48	81.84	84.92	78.75	61.79	74.93	78.23	78.41	76.64	82.45	82.26	81.39
2039	82.03	83.42	86.56	80.27	62.99	76.38	79.74	79.93	78.12	84.05	83.85	82.96
2040	83.37	84.77	87.97	81.58	64.01	77.62	81.04	81.23	79.39	85.41	85.21	84.31
2041	85.23	86.67	89.94	83.40	65.44	79.36	82.85	83.05	81.17	87.32	87.12	86.20

TABLE 6a												
	Renewable Avoided Costs											
Renewable Fixed Price Option for Solar QF												
On-Peak Forecast (\$/MWH)												
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	28.36	22.61	15.76	14.86	12.61	17.11	24.11	27.11	25.11	23.86	26.86	31.61
2017	30.11	28.36	24.86	21.11	19.61	20.61	28.11	31.11	29.61	27.86	28.86	33.86
2018	31.86	31.26	28.26	22.28	21.43	21.43	30.08	33.52	30.78	28.76	32.01	35.86
2019	34.10	32.11	28.13	23.86	22.16	23.29	31.83	35.24	33.53	31.54	32.68	38.37
2020	78.62	78.60	77.84	78.30	81.50	80.60	80.29	80.17	78.88	77.91	78.74	77.73
2021	80.39	80.63	79.12	80.20	83.04	82.28	81.71	82.22	80.71	79.70	81.00	79.67
2022	82.21	82.08	80.18	81.92	84.89	83.87	83.41	83.38	82.27	81.27	82.70	81.25
2023	84.12	83.69	81.71	83.78	86.23	85.50	85.15	84.78	83.94	82.78	84.50	83.39
2024	85.22	85.37	83.41	85.43	88.16	87.14	87.03	86.76	86.58	84.19	85.19	85.32
2025	87.19	87.52	85.33	87.68	91.12	89.95	88.99	89.12	88.30	86.06	87.23	86.87
2026	89.59	89.26	87.80	89.99	94.44	90.96	90.96	91.37	91.08	88.02	89.85	88.91
2027	91.36	90.92	89.26	91.39	97.36	92.76	92.40	93.84	92.68	89.85	91.14	90.67
2028	93.02	91.98	89.96	93.31	98.86	94.00	94.71	94.72	93.84	91.84	92.91	92.13
2029	95.05	94.81	92.15	95.53	105.55	96.99	97.06	97.06	97.11	93.75	94.56	94.45
2030	97.08	96.79	94.51	97.40	108.58	100.60	98.45	98.33	99.71	95.58	96.15	96.19
2031	98.83	98.33	96.70	100.05	110.63	103.81	100.25	101.19	101.40	97.58	98.69	98.25
2032	100.47	99.96	98.30	101.71	112.47	105.53	101.91	102.87	103.08	99.20	100.32	99.88
2033	102.68	102.16	100.47	103.95	114.95	107.86	104.16	105.14	105.36	101.38	102.53	102.08
2034	104.66	104.13	102.41	105.96	117.16	109.94	106.16	107.16	107.38	103.34	104.51	104.05
2035	106.68	106.15	104.39	108.01	119.43	112.06	108.21	109.23	109.46	105.34	106.53	106.06
2036	108.44	107.90	106.11	109.79	121.40	113.91	110.00	111.04	111.27	107.08	108.29	107.81
2037	110.84	110.28	108.46	112.21	124.08	116.43	112.43	113.49	113.73	109.44	110.68	110.19
2038	112.98	112.41	110.55	114.38	126.47	118.68	114.60	115.68	115.92	111.55	112.82	112.32
2039	115.16	114.58	112.68	116.59	128.92	120.97	116.81	117.91	118.16	113.71	115.00	114.49
2040	117.06	116.47	114.54	118.51	131.04	122.96	118.74	119.86	120.11	115.58	116.89	116.37
2041	119.65	119.05	117.07	121.13	133.94	125.68	121.37	122.51	122.76	118.14	119.48	118.95

TABLE 6b												
	Renewable Avoided Costs											
Renewable Fixed Price Option for Solar QF												
Off-Peak Forecast (\$/MWH)												
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	25.76	20.86	14.11	11.56	6.46	10.26	15.86	21.11	21.11	21.36	23.61	26.86
2017	25.86	24.36	22.36	15.86	13.86	12.86	19.86	25.36	25.61	24.86	25.86	28.11
2018	26.32	28.27	25.71	19.61	14.83	12.69	19.86	27.19	27.08	25.50	28.35	30.77
2019	30.00	28.25	25.91	18.31	15.97	14.80	22.99	29.42	29.71	28.83	30.00	32.63
2020	62.76	63.02	64.56	63.31	59.92	60.16	60.45	61.61	62.52	63.74	63.55	63.99
2021	64.93	64.15	65.85	64.48	61.58	61.62	62.27	62.62	63.78	65.82	63.38	65.09
2022	65.85	65.52	67.77	65.49	62.45	62.82	64.33	63.35	65.00	67.04	64.42	66.29
2023	66.70	66.75	69.10	67.28	62.84	64.01	65.40	64.85	66.14	68.41	65.38	67.63
2024	67.25	67.31	70.47	67.09	63.18	65.92	64.75	65.12	66.62	68.68	67.42	68.05
2025	68.62	68.60	71.94	68.08	63.17	66.28	66.12	67.12	67.23	70.19	69.68	69.06
2026	68.95	69.85	72.28	68.56	63.85	67.22	67.05	67.75	67.05	71.12	69.85	69.89
2027	71.31	71.29	73.13	70.34	63.69	68.45	68.79	68.16	68.57	73.22	70.67	71.18
2028	72.28	72.90	75.41	72.10	63.09	69.98	70.15	68.82	70.20	73.79	71.48	73.41
2029	72.78	73.60	76.79	73.50	58.25	70.29	71.37	70.00	71.53	74.58	73.61	74.68
2030	73.91	74.82	78.36	73.64	58.00	70.89	72.02	72.19	72.00	75.99	75.36	76.23
2031	75.51	76.70	79.40	74.00	59.17	70.67	73.55	73.71	72.16	77.24	77.07	76.31
2032	76.76	77.97	80.71	75.23	60.15	71.83	74.76	74.93	73.35	78.52	78.34	77.57
2033	78.46	79.69	82.50	76.89	61.48	73.42	76.42	76.58	74.97	80.25	80.07	79.29
2034	79.97	81.23	84.09	78.37	62.66	74.84	77.89	78.06	76.42	81.80	81.62	80.82
2035	81.52	82.80	85.71	79.88	63.87	76.28	79.39	79.57	77.89	83.38	83.19	82.38
2036	82.86	84.17	87.13	81.20	64.93	77.54	80.70	80.88	79.18	84.76	84.57	83.74
2037	84.69	86.03	89.05	83.00	66.36	79.25	82.49	82.67	80.93	86.63	86.44	85.59
2038	86.33	87.69	90.77	84.60	67.64	80.78	84.08	84.26	82.49	88.30	88.11	87.24
2039	87.99	89.38	92.52	86.23	68.95	82.34	85.70	85.89	84.08	90.01	89.81	88.92
2040	89.45	90.85	94.05	87.66	70.09	83.70	87.12	87.31	85.47	91.49	91.29	90.39
2041	91.42	92.86	96.13	89.59	71.63	85.55	89.04	89.24	87.36	93.51	93.31	92.39

WIND INTEGRATION

TABLE 7							
Wind Integration							
Year	Cost						
2015	3.77						
2016	3.84						
2017	3.91						
2018	3.99						
2019	4.07						
2020	4.15						
2021	4.23						
2022	4.31						
2023	4.39						
2024	4.47						
2025	4.56						
2026	4.65						
2027	4.74						
2028	4.83						
2029	4.92						
2030	5.02						
2031	5.12						
2032	5.21						
2033	5.31						
2034	5.42						
2035	5.52						
2036	5.63						
2037	5.74						
2038	5.85						
2039	5.96						
2040	6.08						

MONTHLY SERVICE CHARGE

Each separately metered QF not associated with a retail Customer account will be charged \$10.00 per month.

INSURANCE REQUIREMENTS

The following insurance requirements are applicable to Sellers with a Standard PPA:

- 1) QFs with nameplate capacity ratings greater than 200 kW are required to secure and maintain a prudent amount of general liability insurance. The Seller must certify to the Company that it is maintaining general liability insurance coverage for each QF at prudent amounts. A prudent amount will be deemed to mean liability insurance coverage for both bodily injury and property damage liability in the amount of not less than \$1,000,000 each occurrence combined single limit, which limits may be required to be increased or decreased by the Company as the Company determines in its reasonable judgment, that economic conditions or claims experience may warrant.
- Such insurance will include an endorsement naming the Company as an additional insured insofar as liability arising out of operations under this schedule and a provision that such liability policies will not be canceled or their limits reduced without 30 days' written notice to the Company. The Seller will furnish the Company with certificates of insurance together with the endorsements required herein. The Company will have the right to inspect the original policies of such insurance.
- 3) QFs with a design capacity of 200 kW or less are encouraged to pursue liability insurance on their own. The Oregon Public Utility Commission in Order No. 05-584 determined that it is inappropriate to require QFs that have a design capacity of 200 kW or less to obtain general liability insurance.

TRANSMISSION AGREEMENTS

If the QF is located outside the Company's service territory, the Seller is responsible for the transmission of power at its cost to the Company's service territory.

INTERCONNECTION REQUIREMENTS

Except as otherwise provided in a generation Interconnection Agreement between the Company and Seller, if the QF is located within the Company's service territory, switching equipment capable of isolating the QF from the Company's system will be accessible to the Company at all times. At the Company's option, the Company may operate the switching equipment described above if, in the sole opinion of the Company, continued operation of the QF in connection with the utility's system may create or contribute to a system emergency.

INTERCONNECTION REQUIREMENTS (Continued)

The QF owner interconnecting with the Company's distribution system must comply with all requirements for interconnection as established pursuant to Commission rule, in the Company's Rules and Regulations (Rule C) or the Company's Interconnection Procedures contained in its FERC Open Access Transmission Tariff (OATT), as applicable. The Seller will bear full responsibility for the installation and safe operation of the interconnection facilities.

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE PRICING UNDER THE STANDARD PPA

A QF will be eligible to receive pricing under the Standard PPA if the nameplate capacity of the QF, together with any other electric generating facility using the same motive force, owned or controlled by the Same Person(s) or Affiliated Person(s), and located at the Same Site, does not exceed 10 MW. A Community-Based or Family-Owned QF is exempt from these restrictions.

Definition of Community-Based

- a. A community project (or a community sponsored project) must have a recognized and established organization located within the county of the project or within 50 miles of the project that has a genuine role in helping the project be developed and must have some not insignificant continuing role with or interest in the project after it is completed and placed in service.
- b. After excluding the passive investor whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit, the equity (ownership) interests in a community sponsored project must be owned in substantial percentage (80 percent or more) by the following persons (individuals and entities): (i) the sponsoring organization, or its controlled affiliates; (ii) members of the sponsoring organization (if it is a membership organization) or owners of the sponsorship organization (if it is privately owned); (iii) persons who live in the county in which the project is located or who live a county adjoining the county in which the project is located; or (iv) units of local government, charities, or other established nonprofit organizations active either in the county in which the project is located or active in a county adjoining the county in which the project is located.

Definition of Family-Owned

After excluding the ownership interest of the passive investor whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit, five or fewer individuals own 50 percent or more of the equity of the project entity, or fifteen or fewer individuals own 90 percent or more of the project entity. A "look through" rule applies to closely held entities that hold the project entity, so that equity held by LLCs, trusts, estates, corporations, partnerships or other similar entities is considered held by the equity owners of the look through entity. An individual is a natural person. In counting to five or fifteen, spouses or children of an equity owner of the project owner who also have an equity interest are aggregated and counted as a single individual.

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE PRICING UNDER THE STANDARD PPA (Continued)

Definition of Person(s) or Affiliated Person(s)

As used above, the term "Same Person(s)" or "Affiliated Person(s)" means a natural person or persons or any legal entity or entities sharing common ownership, management or acting jointly or in concert with or exercising influence over the policies or actions of another person or entity. However, two facilities will not be held to be owned or controlled by the Same Person(s) or Affiliated Person(s) solely because they are developed by a single entity.

Furthermore, two facilities will not be held to be owned or controlled by the Same Person(s) or Affiliated Person(s) if such common person or persons is a "passive investor" whose ownership interest in the QF is primarily related to utilizing production tax credits, green tag values and MACRS depreciation as the primary ownership benefit and the facilities at issue are independent family-owned or community-based projects. A unit of Oregon local government may also be a "passive investor" in a community-based project if the local governmental unit demonstrates that it will not have an equity ownership interest in or exercise any control over the management of the QF and that its only interest is a share of the cash flow from the QF, which share will not exceed 20%. The 20% cash flow share limit may only be exceeded for good cause shown and only with the prior approval of the Commission.

Definition of Same Site

For purposes of the foregoing, generating facilities are considered to be located at the same site as the QF for which qualification for pricing under the Standard PPA is sought if they are located within a five-mile radius of any generating facilities or equipment providing fuel or motive force associated with the QF for which qualification for pricing under the Standard PPA is sought.

Definition of Shared Interconnection and Infrastructure

QFs otherwise meeting the above-described separate ownership test and thereby qualified for entitlement to pricing under the Standard PPA will not be disqualified by utilizing an interconnection or other infrastructure not providing motive force or fuel that is shared with other QFs qualifying for pricing under the Standard PPA so long as the use of the shared interconnection complies with the interconnecting utility's safety and reliability standards, interconnection agreement requirements and Prudent Electrical Practices as that term is defined in the interconnecting utility's approved Standard PPA.

OTHER DEFINITIONS

Mid-C Index Price

As used in this schedule, the daily Mid-C Index Price shall be the Day Ahead Intercontinental Exchange ("ICE") for the bilateral OTC market for energy at the Mid-C Physical for Average

OTHER DEFINITIONS (Continued)

On-Peak Power and Average Off-Peak Power found on the following website: https://www.theice.com/products/OTC/Physical-Energy/Electricity. In the event ICE no longer publishes this index, PGE and the Seller agree to select an alternative successor index representative of the Mid-C trading hub.

Definition of RPS Attributes

As used in this schedule, RPS Attributes means all attributes related to the Net Output generated by the Facility that are required in order to provide PGE with "qualifying electricity," as that term is defined in Oregon's Renewable Portfolio Standard Act, Ore. Rev. Stat. 469A.010, in effect at the time of execution of this Agreement. RPS Attributes do not include Environmental Attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity and not needed to ensure that there are zero net emissions associated with the generation of electricity.

Definition of Environmental Attributes

As used in this schedule, Environmental Attributes shall mean any and all claims, credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical, or other substance to the air, soil or water. Environmental Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil, or water such as (subject to the foregoing) sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; and (2) any avoided emissions of carbon dioxide (CO2), methane (CH4), and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere.

Definition of Resource Sufficiency Period

This is the period from the current year through 2020.

Definition of Resource Deficiency Period

This is the period from 2021 through 2034.

Definition of Renewable Resource Sufficiency Period

This is the period from the current year through 2019.

Definition of Renewable Resource Deficiency Period

This is the period from 2020 through 2034.

SCHEDULE 201 (Concluded)

DISPUTE RESOLUTION

Upon request, the QF will provide the purchasing utility with documentation verifying the ownership, management and financial structure of the QF in reasonably sufficient detail to allow the utility to make an initial determination of whether or not the QF meets the above-described criteria for entitlement to pricing under the Standard PPA.

The QF may present disputes to the Commission for resolution using the following process:

The QF may file a complaint asking the Commission to adjudicate disputes regarding the formation of the standard contract. The QF may not file such a complaint during any 15-day period in which the utility has the obligation to respond, but must wait until the 15-day period has passed.

The utility may respond to the complaint within ten days of service.

The Commission will limit its review to the issues identified in the complaint and response, and utilize a process similar to the arbitration process adopted to facilitate the execution of interconnection agreements among telecommunications carriers. See OAR 860, Division 016. The administrative law judge will not act as an arbitrator.

SPECIAL CONDITIONS

- 1. Delivery of energy by Seller will be at a voltage, phase, frequency, and power factor as specified by the Company.
- 2. If the Seller also receives retail Electricity Service from the Company at the same location, any payments under this schedule will be credited to the Seller's retail Electricity Service bill. At the option of the Customer, any net credit over \$10.00 will be paid by check to the Customer.
- 3. Unless required by state or federal law, if the 1978 Public Utility Regulatory Policies Act (PURPA) is repealed, PPAs entered into pursuant to this schedule will not terminate prior to the Standard or Negotiated PPA's termination date.

TERM OF AGREEMENT

Not less than one year and not to exceed 20 years.

From: Angeline Chong <Angeline.Chong@pgn.com>

Sent: Tuesday, March 21, 2017 3:08 PM

To: Talbott, Will

Subject: Executable agreements

Attachments: Executable cover letter Blue Marmot VII.pdf; Executable cover letter Blue Marmot XI.pdf; Executable

PPA and Schedule for Off system Renew Solar Blue Marmot VII.pdf; Executable PPA and Schedule for

Off system Renew Solar Blue Marmot IX.pdf

Please see the attached. Thanks.

Angeline D. Chong|
Portland General Electric |
121 SW Salmon St. 3WTC0306 | Portland, Oregon 97204|
W: 503-464-7343 | F: 503-464-2605 |

E: angeline.chong@pgn.com



March 21, 2017

Will Talbott
EDP Renewables north America LLC
Development-Western Region
53 SW Yamhill Street, Portland OR 97204
will.talbott@epdr.com

RE: Transmittal of Executable Standard PPA

Blue Marmot VII project, a proposed 10 megawatt Solar QF

Dear Talbott,

Thank you for your interest in entering into a Standard Power Purchase Agreement (Standard PPA) with Portland General Electric (PGE). PGE received your written request for an executable Standard PPA on February 28, 2017. PGE has determined that you have provided sufficient information to allow PGE to prepare an executable Standard PPA.

Enclosed please find an executable Standard PPA for your **Blue Marmot VII** project, a proposed 10 megawatt **Solar** generating facility that was self certified as a qualifying facility (QF) pursuant to 18 CFR 292.207. PGE understands that **Blue Marmot VII** LLC is a Limited Liability Corporation formed under the laws of the State of **Delaware** is the owner of the **Blue Marmot VII** project and will be the Seller under the Standard PPA. If any of the information contained in the enclosed executable Standard PPA is incorrect, please inform PGE immediately and **do not execute the agreement**.

If Seller executes the enclosed agreement without alteration and returns the partially executed agreement to PGE for full execution, Seller will have established a legally enforceable obligation. Seller is entitled to receive PGE's Renewable Avoided Costs in effect at the time Seller executes the enclosed agreement without alteration. If the PGE Renewable Avoided Costs in effect on the date Seller executes the enclosed agreement are different from the Renewable Avoided Costs reflected in the enclosed agreement, then Seller must send PGE a written request to revise the enclosed agreement to reflect the then applicable Renewable Avoided Costs. No Standard PPA between PGE and Seller will be valid or binding if it contains Renewable Avoided Costs that differ from those in effect on the date the Seller executes the Standard PPA.

Seller is not authorized to revise the enclosed agreement. If Seller seeks any changes, you will need to send PGE a written request for a new agreement. If you have proposed substantive changes to your project or to the variable term of the executable Standard

Mr. Talbott March 21, 2017 Page 2 of 2

PPA, PGE will treat the proposal as a request for a new draft Standard PPA and, within 15 business days of receiving your written request for changes, PGE will send you either a new draft Standard PPA or a request for additional or clarifying information. If you have proposed ministerial, typographical, or other non-substantive changes to the enclosed executable Standard PPA, then within 15 business days of receiving your written request for changes, PGE will send you either a revised executable Standard PPA or a request for additional or clarifying information.

This letter summarizes certain aspects of the Standard PPA process; it does not address every detail of the process. Additional details will be provided for each stage in PGE's letters associated with each stage. If you have any questions, please contact PGE's Power Production Coordinator at (503) 464-8000.

Sincerely,

Angeline D. Chong

Portland General Electric |

121 SW Salmon St. 3WTC0306 | Portland, Oregon 97204|

W: 503-464-7343 | F: 503-464-2605 |

E: angeline.chong@pgn.com

enclosure: Executable Standard PPA for 's Blue Marmot VII Project

cc.

Blue Marmot VII LLC c/o EDP Renewables North America LLC Attention: General Counsel 808 Travis, Suite 700 Houston, Texas 77002



March 21, 2017

Will Talbott
EDP Renewables north America LLC
Development-Western Region
53 SW Yamhill Street, Portland OR 97204
will.talbott@epdr.com

RE: Transmittal of Executable Standard PPA

Blue Marmot XI project, a proposed 10 megawatt Solar QF

Dear Talbott,

Thank you for your interest in entering into a Standard Power Purchase Agreement (Standard PPA) with Portland General Electric (PGE). PGE received your written request for an executable Standard PPA on **February 28, 2017**. PGE has determined that you have provided sufficient information to allow PGE to prepare an executable Standard PPA.

Enclosed please find an executable Standard PPA for your **Blue Marmot XI** project, a proposed 10 megawatt **Solar** generating facility that was self certified as a qualifying facility (QF) pursuant to 18 CFR 292.207. PGE understands that **Blue Marmot IX LLC** is a Limited Liability Corporation formed under the laws of the State of **Delaware** is the owner of the **Blue Marmot XI** project and will be the Seller under the Standard PPA. If any of the information contained in the enclosed executable Standard PPA is incorrect, please inform PGE immediately and **do not execute the agreement**.

If Seller executes the enclosed agreement without alteration and returns the partially executed agreement to PGE for full execution, Seller will have established a legally enforceable obligation. Seller is entitled to receive PGE's Renewable Avoided Costs in effect at the time Seller executes the enclosed agreement without alteration. If the PGE Renewable Avoided Costs in effect on the date Seller executes the enclosed agreement are different from the Renewable Avoided Costs reflected in the enclosed agreement, then Seller must send PGE a written request to revise the enclosed agreement to reflect the then applicable Renewable Avoided Costs. No Standard PPA between PGE and Seller will be valid or binding if it contains Renewable Avoided Costs that differ from those in effect on the date the Seller executes the Standard PPA.

Seller is not authorized to revise the enclosed agreement. If Seller seeks any changes, you will need to send PGE a written request for a new agreement. If you have proposed substantive changes to your project or to the variable term of the executable Standard

Mr. Talbott March 21, 2017 Page 2 of 2

PPA, PGE will treat the proposal as a request for a new draft Standard PPA and, within 15 business days of receiving your written request for changes, PGE will send you either a new draft Standard PPA or a request for additional or clarifying information. If you have proposed ministerial, typographical, or other non-substantive changes to the enclosed executable Standard PPA, then within 15 business days of receiving your written request for changes, PGE will send you either a revised executable Standard PPA or a request for additional or clarifying information.

This letter summarizes certain aspects of the Standard PPA process; it does not address every detail of the process. Additional details will be provided for each stage in PGE's letters associated with each stage. If you have any questions, please contact PGE's Power Production Coordinator at (503) 464-8000.

Sincerely,

Angeline D. Chong

Portland General Electric |

121 SW Salmon St. 3WTC0306 | Portland, Oregon 97204

W: 503-464-7343 | F: 503-464-2605 |

E: angeline.chong@pgn.com

enclosure: Executable Standard PPA for 's Blue Marmot IX Project

cc.

Blue Marmot VII LLC c/o EDP Renewables North America LLC Attention: General Counsel 808 Travis, Suite 700 Houston, Texas 77002 Blue Marmot/201 Talbott/127 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

STANDARD RENEWABLE OFF-SYSTEM VARIABLE POWER PURCHASE AGREEMENT

THIS AGREEMENT is between <u>Blue Marmot IX LLC</u> ("Seller") and Portland General Electric Company ("PGE") (hereinafter each a "Party" or collectively, "Parties") and is effective upon execution by both Parties ("Effective Date").

RECITALS

Seller intends to construct, own, operate and maintain a <u>Solar</u> facility for the generation of electric power located in <u>Lake (W -120.382, N 42.260)</u> County, <u>Oregon</u> with a Nameplate Capacity Rating of <u>10,000</u> kilowatt ("kW"), as further described in Exhibit A ("Facility"); and

Seller intends to operate the Facility as a "Qualifying Facility," as such term is defined in Section 3.1.3, below.

Seller shall sell and PGE shall purchase the entire Net Output, as such term is defined in Section 1.21, below, from the Facility in accordance with the terms and conditions of this Agreement.

AGREEMENT

NOW, THEREFORE, the Parties mutually agree as follows:

SECTION 1: DEFINITIONS

When used in this Agreement, the following terms shall have the following meanings:

- 1.1. "As-built Supplement" means the supplement to Exhibit A provided by Seller in accordance with Section 4.3 following completion of construction of the Facility, describing the Facility as actually built.
- 1.2. "Base Hours" is defined as the total number of hours in each Contract Year (8,760 or 8,784 for leap year)
- 1.3. "Billing Period" means from the start of the first day of each calendar month to the end of the last day of each calendar month.
- 1.4. "Cash Escrow" means an agreement by two parties to place money into the custody of a third party for delivery to a grantee only after the fulfillment of the conditions specified.
- 1.5. "Commercial Operation Date" means the date that the Facility is deemed by PGE to be fully operational and reliable. PGE may, at its discretion require, among other things, that all of the following events have occurred:
- 1.5.1. (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from a Licensed

Blue Marmot/201 Talbott/128 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

Professional Engineer ("LPE") acceptable to PGE in its reasonable judgment stating that the Facility is able to generate electric power reliably in accordance with the terms and conditions of this Agreement (certifications required under this Section 1.5 can be provided by one or more LPEs);

- 1.5.2. Start-Up Testing of the Facility has been completed in accordance with Section 1.36;
- 1.5.3. (facilities with nameplate under 500 kW exempt from following requirement) After PGE has received notice of completion of Start-Up Testing, PGE has received a certificate addressed to PGE from an LPE stating that the Facility has operated for testing purposes under this Agreement and was continuously mechanically available for operation for a minimum of 120 hours. The Facility must provide ten (10) working days written notice to PGE prior to the start of the initial testing period. If the mechanical availability of the Facility is interrupted during this initial testing period or any subsequent testing period, the Facility shall promptly start a new Test Period and provide PGE forty-eight (48) hours written notice prior to the start of such testing period;
- 1.5.4. (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from an LPE stating that all required interconnection facilities have been constructed and all required interconnection tests have been completed;
- 1.5.5. (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from an LPE stating that Seller has obtained all Required Facility Documents and, if requested by PGE in writing, has provided copies of any or all such requested Required Facility Documents;
- 1.5.6. PGE has received a copy of the executed Generation Interconnection and Transmission Agreements.
- 1.6. "Contract Price" means the applicable price, including on-peak and off-peak prices, as specified in the Schedule.
- 1.7. "Contract Year" means each twelve (12) month period commencing upon the Commercial Operation Date or its anniversary during the Term, except the final Contract Year will be the period from the last anniversary of the Commercial Operation Date during the Term until the end of the Term.
 - 1.8. "Effective Date" has the meaning set forth in Section 2.1.
- 1.9. "Environmental Attributes" shall mean any and all claims, credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical or other substance to the air, soil or water. Environmental Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil or water such as (subject to the foregoing) sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; and (2) any avoided emissions of carbon dioxide (CO2), methane (CH4), and other greenhouse gasses (GHGs) that have been determined by the United Nations

Blue Marmot/201 Talbott/129 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

Intergovernmental Panel on Climate Change to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere.

- 1.10. "Facility" has the meaning set forth in the Recitals.
- 1.11. "Generation Interconnection Agreement" means an agreement governing the interconnection of the Facility with **Pacificorp** electric system.
- 1.12. "Generation Unit" means each separate electrical generator that contributes toward Nameplate Capacity Rating included in Exhibit A. For solar facilities, a generating unit is a complete solar electrical generation system within the Facility that is able to generate and deliver energy to the Point of Delivery independent of other Generation Units within the same Facility.
- 1.13. "Letter of Credit" means an engagement by a bank or other person made at the request of a customer that the issuer will honor drafts or other demands for payment upon compliance with the conditions specified in the letter of credit.
- 1.14. "Licensed Professional Engineer" or "LPE" means a person who is licensed to practice engineering in the state where the Facility is located, who has no economic relationship, association, or nexus with the Seller, and who is not a representative of a consulting engineer, contractor, designer or other individual involved in the development of the Facility, or of a manufacturer or supplier of any equipment installed in the Facility. Such Licensed Professional Engineer shall be licensed in an appropriate engineering discipline for the required certification being made and be acceptable to PGE in its reasonable judgment.
- 1.15. "Lost Energy" means "Lost Energy" means ((the Guarantee of Mechanical Availability as set forth in 3.1.10 / MAP) X Net Output for a Calendar Year) Net Output for the Calendar Year. Lost Energy shall be zero unless the result of the calculation in this subsection results in a positive number.
- 1.16. "Lost Energy Value" means Lost Energy X the excess of the annual time-weighted average Mid-C Index Price for On Peak Hours and Off Peak Hours over the time weighted average Contract Price for On Peak and Off Peak Hours for the corresponding time period (provided that such excess shall not exceed the Contract Price and further provided that Lost Energy is deemed to be zero prior to reaching the Commercial Operation Date) plus any reasonable costs incurred by PGE to purchase replacement power and/or transmission to deliver the replacement power to the Point of Delivery (For Start-Up Lost Energy Value See 1.35).
- 1.17. "Mechanical Availability Percentage" or "MAP" shall mean that percentage for any Contract Year for the Facility calculated in accordance with the following formula:

MAP = 100 X (Operational Hours) /(Base Hours X Number of Units)

1.18. "Mid-C Index Price" means the Day Ahead Intercontinental Exchange ("ICE") index price for the bilateral OTC market for energy at the Mid-C Physical for Average On Peak Power and Average Off Peak Power found on the following website:

Blue Marmot/201 Talbott/130 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

https://www.theice.com/products/OTC/Physical-Energy/Electricity. In the event ICE no longer publishes this index, PGE and the Seller agree to select an alternative successor index representative of the Mid-C trading hub.

- 1.19. "Nameplate Capacity Rating" means the maximum capacity of the Facility as stated by the manufacturer, expressed in kW, which shall not exceed 10,000 kW.
- 1.20. "Net Dependable Capacity" means the maximum capacity the Facility can sustain over a specified period modified for seasonal limitations, if any, and reduced by the capacity required for station service or auxiliaries.
- 1.21. "Net Output" means all energy expressed in kWhs produced by the Facility, less station and other onsite use and less transformation and transmission losses.
- 1.22. "Number of Units" means the number of Generation Units in the Facility as specified in Exhibit A.
 - 1.23. "Off-Peak Hours" has the meaning provided in the Schedule.
 - 1.24. "On-Peak Hours" has the meaning provided in the Schedule.
- 1.25. "Operational Hours" for the Facility means the total across all Generation Units of the number of hours each of the Facility's Generation Units are potentially capable of producing power at its Nameplate Capacity Rating regardless of actual weather conditions, season and the time of day or night, without any mechanical operating constraint or restriction, and potentially capable of delivering such power to the Point of Delivery in a Contract Year. During up to, but not more than, two hundred (200) hours of Planned Maintenance during a Contract Year for each Generation Unit and hours during which an event of Force Majeure exists, a Generation Unit shall be considered potentially capable of delivering such power to the Point of Delivery. For example, in the absence of any Planned Maintenance beyond 200 hours on any Generation Unit or Event of Force Majeure, the Operational Hours for a wind farm with five (5) separate two (2) MW turbines would be 43,800 for a Contract Year.
- 1.26. "Planned Maintenance" means outages scheduled ninety (90) days in advance, with PGE's prior written consent, which shall not be unreasonably withheld.
 - 1.27. "Point of Delivery" means the PGE system.
- 1.28. "Pre-Commercial Operation Date Minimum Net Output" shall mean, unless such MWh is specifically set forth by Seller in Exhibit A, an amount in MWh equal to seventy-five percent (75%) of Nameplate Capacity Rating X thirty percent (30%) for a wind or other renewable QF or fifty percent (50%) for a solar QF X (whole months since the date selected in Section 2.2.1 / 12) X (8760 hours 200 hours (assumed Planned Maintenance)) for each month. If Seller has provided specific expected monthly Net Output amounts for the Facility in Exhibit A, "Pre-Commercial Operation Date Minimum Net Output" shall mean seventy-five percent (75%) X expected net output set forth in Exhibit A for each month.

Blue Marmot/201 Talbott/131 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

- 1.29. "Prime Rate" means the publicly announced prime rate or reference rate for commercial loans to large businesses with the highest credit rating in the United States in effect from time to time quoted by Citibank, N.A. If a Citibank, N.A. prime rate is not available, the applicable Prime Rate shall be the announced prime rate or reference rate for commercial loans in effect from time to time quoted by a bank with \$10 billion or more in assets in New York City, N.Y., selected by the Party to whom interest based on the prime rate is being paid.
- 1.30. "Prudent Electrical Practices" means those practices, methods, standards and acts engaged in or approved by a significant portion of the electric power industry in the Western Electricity Coordinating Council that at the relevant time period, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with good business practices, reliability, economy, safety and expedition, and which practices, methods, standards and acts reflect due regard for operation and maintenance standards recommended by applicable equipment suppliers and manufacturers, operational limits, and all applicable laws and regulations. Prudent Electrical Practices are not intended to be limited to the optimum practice, method, standard or act to the exclusion of all others, but rather to those practices, methods and acts generally acceptable or approved by a significant portion of the electric power generation industry in the relevant region, during the relevant period, as described in the immediate preceding sentence.
- 1.31. "Required Facility Documents" means all licenses, permits, authorizations, and agreements necessary for construction, operation, interconnection, and maintenance of the Facility including without limitation those set forth in Exhibit B.
- 1.32. "RPS Attributes" means all attributes related to the Net Output generated by the Facility that are required in order to provide PGE with "qualifying electricity," as that term is defined in Oregon's Renewable Portfolio Standard Act, Ore. Rev. Stat. 469A.010, in effect at the time of execution of this Agreement. RPS Attributes do not include Environmental Attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity and not needed to ensure that there are zero net emissions associated with the generation of electricity.
- 1.33. "Schedule" shall mean PGE Schedule 201 filed with the Oregon Public Utilities Commission ("Commission") in effect on the Effective Date of this Agreement and attached hereto as Exhibit D, the terms of which are hereby incorporated by reference.
- 1.34. "Senior Lien" means a prior lien which has precedence as to the property under the lien over another lien or encumbrance
- 1.35. "Start-Up Lost Energy Value" means for the period after the date specified in Section 2.2.2 but prior to achievement of the Commercial Operation Date: zero, unless the Net Output is less than the pro-rated Pre-Commercial Operation Date Minimum Net Output for the applicable delay period, and the time-weighted average of the delay period's Mid-C Index Price for On-Peak Hours and Off-Peak Hours is greater

Blue Marmot/201 Talbott/132 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

than the time-weighted average of the delay period's Contract Price for On-Peak Hours and Off-Peak Hours, in which case Startup Lost Energy Value equals: (pro-rated Pre-Commercial Operation Date Minimum Net Output for the applicable period - Net Output for the applicable period) X (the lower of: the time-weighted average of the Contract Price for On-Peak hours and Off-Peak Hours during the applicable period; or (the time-weighted average of the Mid-C Index Price for On-Peak Hours and Off-Peak Hours during the applicable period). The time-weighted average in this section will reflect the relative proportions of On-Peak Hours and Off-Peak Hours in each day.

- 1.36. "Start-Up Testing" means the completion of applicable required factory and start-up tests as set forth in Exhibit C.
- 1.37. "Step-in Rights" means the right of one party to assume an intervening position to satisfy all terms of an agreement in the event the other party fails to perform its obligations under the agreement.
- 1.38. "Term" shall mean the period beginning on the Effective Date and ending on the Termination Date.
- 1.39. "Test Period" shall mean a period of sixty (60) days or a commercially reasonable period determined by the Seller.
- 1.40. "Transmission Agreement" means an agreement executed by the Seller and the Transmission Provider(s) for Transmission Services.
- 1.41. "Transmission Curtailment" means a limitation on Seller's ability to deliver any portion of the scheduled energy to PGE due to the unavailability of transmission to the Point of Delivery (for any reason other than Force Majeure).
- 1.42. "Transmission Curtailment Replacement Energy Cost" means the greater of zero or the amount calculated as: ((Mid-C Index Price Contract Price) X curtailed energy) for periods of Transmission Curtailment.
- 1.43. "Transmission Provider(s)" means the signatory (other than the Seller) to the Transmission Agreement.
- 1.44. "Transmission Services" means any and all services (including but not limited to ancillary services and control area services) required for the firm transmission and delivery of Energy from the Facility to the Point of Delivery for a term not less than the Term of this Agreement.

References to Recitals, Sections, and Exhibits are to be the recitals, sections and exhibits of this Agreement.

SECTION 2: TERM; COMMERCIAL OPERATION DATE

2.1. This Agreement shall become effective upon execution by both Parties ("Effective Date").

Blue Marmot/201 Talbott/133 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

- 2.2. Time is of the essence of this Agreement, and Seller's ability to meet certain requirements prior to the Commercial Operation Date and to complete all requirements to establish the Commercial Operation Date is critically important. Therefore,
 - 2.2.1. By March 1, 2020 Seller shall begin initial deliveries of Net Output; and
- 2.2.2. By <u>March 31, 2020</u> Seller shall have completed all requirements under Section 1.5 and shall have established the Commercial Operation Date.
- 2.2.3. Unless the Parties agree in writing that a later Commercial Operation Date is reasonable and necessary, the Commercial Operation Date shall be no more than three (3) years from the Effective Date. PGE will not unreasonably withhold agreement to a Commercial Operation Date that is more than three (3) years from the Effective date if the Seller has demonstrated that a later Commercial Operation Date is reasonable and necessary.
- 2.3. This Agreement shall terminate on the date <u>18 years after the effective</u> <u>date</u>, or the date the Agreement is terminated in accordance with Section 8 or 11, whichever is earlier ("Termination Date").

SECTION 3: REPRESENTATIONS AND WARRANTIES

- 3.1. Seller and PGE represent, covenant, and warrant as follows:
- 3.1.1. Seller warrants it is a <u>Limited Liability Company</u> duly organized under the laws of **Delaware**.
- 3.1.2. Seller warrants that the execution and delivery of this Agreement does not contravene any provision of, or constitute a default under, any indenture, mortgage, or other material agreement binding on Seller or any valid order of any court, or any regulatory agency or other body having authority to which Seller is subject.
- 3.1.3. Seller warrants that the Facility is and shall for the Term of this Agreement continue to be a "Qualifying Facility" ("QF") as that term is defined in the version of 18 C.F.R. Part 292 in effect on the Effective Date. Seller has provided the appropriate QF certification, which may include a Federal Energy Regulatory Commission ("FERC") self-certification to PGE prior to PGE's execution of this Agreement. At any time during the Term of this Agreement, PGE may require Seller to provide PGE with evidence satisfactory to PGE in its reasonable discretion that the Facility continues to qualify as a QF under all applicable requirements.
- 3.1.4. Seller warrants that it has not within the past two (2) years been the debtor in any bankruptcy proceeding, and Seller is and will continue to be for the Term of this Agreement current on all of its financial obligations.
- 3.1.5. Seller warrants that during the Term of this Agreement, all of Seller's right, title and interest in and to the Facility shall be free and clear of all liens and encumbrances other than liens and encumbrances arising from third-party financing of the Facility other than workers', mechanics', suppliers' or similar liens, or tax liens, in each case arising in the ordinary course of business that are either not yet due and

Blue Marmot/201 Talbott/134 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

payable or that have been released by means of a performance bond acceptable to PGE posted within eight (8) calendar days of the commencement of any proceeding to foreclose the lien.

- 3.1.6. Seller warrants that it will design and operate the Facility consistent with Prudent Electrical Practices.
- 3.1.7. Seller warrants that the Facility has a Nameplate Capacity Rating not greater than 10,000 kW.
 - 3.1.8. Seller warrants that Net Dependable Capacity of the Facility is 10,000 kW.
- 3.1.9. Seller estimates that the average annual Net Output to be delivered by the Facility to PGE is **21,891,000** kilowatt-hours ("kWh"), which amount PGE will include in its resource planning.
- 3.1.10. Seller represents and warrants that the Facility shall achieve the following Mechanical Availability Percentages ("Guarantee of Mechanical Availability"):
- 3.1.10.1. Ninety percent (90%) beginning in the first Contract Year and extending through the Term for the Facility, if the Facility was operational and sold electricity to PGE or another buyer prior to the Effective Date of this Agreement; or
- 3.1.10.2. Ninety percent (90%) beginning in Contract Year three and extending throughout the remainder of the Term.
- 3.1.10.3. Annually, within 90 days of the end of each Contract Year, Seller shall send to PGE a detailed written report demonstrating and providing evidence of the actual MAP for the previous Contract Year.
- 3.1.10.4. Seller's failure to meet the Guarantee of Mechanical Availability in a Calendar Year shall result in damages payable to PGE by Seller equal to the Lost Energy Value. PGE shall bill Seller for such damages in accordance with Section 7.
- 3.1.11. Seller will deliver from the Facility to PGE at the Point of Delivery Net Output not to exceed a maximum of <u>33,750,000</u> kWh of Net Output during each Contract Year ("Maximum Net Output"). The cost of delivering energy from the Facility to PGE is the sole responsibility of the Seller.
- 3.1.12. By the Commercial Operation Date, Seller has entered into a Generation Interconnection Agreement for a term not less than the term of this Agreement.
- 3.1.13. PGE warrants that it has not within the past two (2) years been the debtor in any bankruptcy proceeding, and PGE is and will continue to be for the Term of this Agreement current on all of its financial obligations.
- 3.1.14. Seller warrants that the Facility satisfies the eligibility requirements specified in the Definition of a Small Cogeneration Facility or Small Power Production Facility Eligible to Receive the Standard Renewable Rates and Standard Renewable PPA in PGE's Schedule and Seller will not make any changes in its ownership, control or management during the term of this Agreement that would cause it to not be in compliance with the Definition of a Small Cogeneration Facility or Small Power

Blue Marmot/201 Talbott/135 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

Production Facility Eligible to Receive the Standard Renewable Rates and Standard Renewable PPA in PGE's Schedule. Seller will provide, upon request by PGE not more frequently than every 36 months, such documentation and information as may be reasonably required to establish Seller's continued compliance with such Definition. PGE agrees to take reasonable steps to maintain the confidentiality of any portion of the above described documentation and information that the Seller identifies as confidential except PGE will provide all such confidential information to the Commission upon the Commission's request.

3.1.15. Seller warrants that it will comply with all requirements necessary for all Transferred RECs (as defined in Section 4.5) associated with Net Output to be issued, monitored, accounted for, and transferred by and through the Western Renewable Energy Generation System consistent with the provisions of OAR 330-160-0005 through OAR 330-160-0050. PGE warrants that it will reasonably cooperate in Seller's efforts to meet such requirements, including, for example serving as the qualified reporting entity for the Facility if the Facility is located in PGE's balancing authority.

SECTION 4: DELIVERY OF POWER, PRICE AND ENVIRONMENTAL ATTRIBUTES

- 4.1. Commencing on the Effective Date and continuing through the Term of this Agreement, Seller shall sell to PGE the entire Net Output delivered from the Facility at the Point of Delivery.
 - 4.2. PGE shall pay Seller the Contract Price for all delivered Net Output.
- 4.3. Upon completion of construction of the Facility, Seller shall provide PGE an As-built Supplement to specify the actual Facility as built. Seller shall not increase the Nameplate Capacity Rating above that specified in Exhibit A or increase the ability of the Facility to deliver Net Output in quantities in excess of the Net Dependable Capacity, or the Maximum Net Output as described in Section 3.1.11 above, through any means including, but not limited to, replacement, modification, or addition of existing equipment, except with prior written notice to PGE. In the event Seller increases the Nameplate Capacity Rating of the Facility to no more than 10,000 kW pursuant to this section, PGE shall pay the Contract Price for the additional delivered Net Output. In the event Seller increases the Nameplate Capacity Rating to greater than 10,000 kW, then Seller shall be required to enter into a new power purchase agreement for all delivered Net Output proportionally related to the increase of Nameplate Capacity above 10,000 kW.
- 4.4. Seller shall provide preschedules for all deliveries of energy hereunder, including identification of receiving and generating control areas, by 9:00:00 PPT on the last business day prior to the scheduled date of delivery. All energy shall be scheduled according to the most current North America Energy Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) scheduling rules and practices. The Parties' respective representatives shall maintain hourly real-time schedule coordination; provided, however, that in the absence of such coordination, the hourly schedule established by the exchange of preschedules shall be considered final. Seller and PGE shall maintain records of hourly energy schedules for accounting and

Blue Marmot/201 Talbott/136 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

operating purposes. The final E-Tag shall be the controlling evidence of the Parties' schedule. All energy shall be prescheduled according to customary WECC scheduling practices. Seller shall make commercially reasonable efforts to schedule in any hour an amount equal to its expected Net Output for such hour. Seller shall maintain a minimum of two years records of Net Output and shall agree to allow PGE to have access to such records and to imbalance information kept by the Transmission Provider.

From the start of the Renewable Resource Deficiency Period through the remainder of the Term of this Agreement, Seller shall provide and PGE shall acquire the RPS Attributes for the Contract Years as specified in the Schedule and Seller shall retain ownership of all other Environmental Attributes (if any). During the Renewable Resource Sufficiency Period, Seller shall retain all Environmental Attributes in accordance with the Schedule. The Contract Price includes full payment for the Net Output and any RPS Attributes transferred to PGE under this Agreement. With respect to Environmental Attributes not transferred to PGE under this Agreement ("Seller-Retained Environmental Attributes") Seller may report under §1605(b) of the Energy Policy Act of 1992 or under any applicable program as belonging to Seller any of the Seller-Retained Environmental Attributes, and PGE shall not report under such program that such Seller-Retained Environmental Attributes belong to it. With respect to RPS Attributes transferred to PGE under this Agreement ("Transferred RECs"), PGE may report under §1605(b) of the Energy Policy Act of 1992 or under any applicable program as belonging to it any of the Transferred RECs, and Seller shall not report under such program that such Transferred RECs belong to it.

SECTION 5: OPERATION AND CONTROL

- 5.1. Seller shall operate and maintain the Facility in a safe manner in accordance with the Generation Interconnection Agreement, and Prudent Electrical Practices. PGE shall have no obligation to purchase Net Output from the Facility to the extent the interconnection of the Facility to PGE's electric system is disconnected, suspended or interrupted, in whole or in part, pursuant to the Generation Interconnection Agreement, or to the extent generation curtailment is required as a result of Seller's noncompliance with the Generation Interconnection Agreement. Seller is solely responsible for the operation and maintenance of the Facility. PGE shall not, by reason of its decision to inspect or not to inspect the Facility, or by any action or inaction taken with respect to any such inspection, assume or be held responsible for any liability or occurrence arising from the operation and maintenance by Seller of the Facility.
- 5.2. Seller agrees to provide sixty (60) days advance written notice of any scheduled maintenance that would require shut down of the Facility for any period of time.
- 5.3. If the Facility ceases operation for unscheduled maintenance, Seller immediately shall notify PGE of the necessity of such unscheduled maintenance, the time when such maintenance has occurred or will occur, and the anticipated duration of such maintenance. Seller shall take all reasonable measures and exercise its best

Blue Marmot/201 Talbott/137 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

efforts to avoid unscheduled maintenance, to limit the duration of such unscheduled maintenance, and to perform unscheduled maintenance during Off-Peak hours.

SECTION 6: CREDITWORTHINESS

In the event Seller: a) is unable to represent or warrant as required by Section 3 that it has not been a debtor in any bankruptcy proceeding within the past two (2) years; b) becomes such a debtor during the Term; or c) is not or will not be current on all its financial obligations, Seller shall immediately notify PGE and shall promptly (and in no less than 10 days after notifying PGE) provide default security in an amount reasonably acceptable to PGE in one of the following forms: Senior Lien, Step-in Rights, a Cash Escrow or Letter of Credit. The amount of such default security that shall be acceptable to PGE shall be equal to: (annual On Peak Hours) X (On Peak Price – Off Peak Price) X (Net Dependable Capacity). Notwithstanding the foregoing, in the event Seller is not current on construction related financial obligations, Seller shall notify PGE of such delinquency and PGE may, in its discretion, grant an exception to the requirements to provide default security if the QF has negotiated financial arrangements with the construction loan lender that mitigate Seller's financial risk to PGE.

SECTION 7: BILLINGS, COMPUTATIONS AND PAYMENTS

- 7.1. On or before the thirtieth (30th) day following the end of each Billing Period, PGE shall send to Seller payment for Seller's deliveries of Net Output to PGE, together with computations supporting such payment. PGE may offset any such payment to reflect amounts owing from Seller to PGE pursuant to this Agreement and any other agreement related to the Facility between the Parties or otherwise. On or before the thirtieth (30th) day following the end of each Contract Year, PGE shall bill for any Lost Energy Value accrued pursuant to this Agreement.
- 7.2. Any amounts owing after the due date thereof shall bear interest at the Prime Rate plus two percent (2%) from the date due until paid; provided, however, that the interest rate shall at no time exceed the maximum rate allowed by applicable law.

SECTION 8: DEFAULT, REMEDIES AND TERMINATION

- 8.1. In addition to any other event that may constitute a default under this Agreement, the following events shall constitute defaults under this Agreement:
- 8.1.1. Breach by Seller or PGE of a representation or warranty, except for Section 3.1.4, set forth in this Agreement.
- 8.1.2. Seller's failure to provide default security, if required by Section 6, prior to delivery of any Net Output to PGE or within 10 days of notice.
- 8.1.3. Seller's failure to meet the Guarantee of Mechanical Availability established in Section 3.1.10 for two consecutive Contract Years or Seller's failure to provide any written report required by that section.
 - 8.1.4. If Seller is no longer a Qualifying Facility.
 - 8.1.5. Failure of PGE to make any required payment pursuant to Section 7.1.

Blue Marmot/201 Talbott/138 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

- 8.1.6. Seller's failure to meet the Commercial Operation Date.
- 8.2. In the event of a default under Section 8.1.6, PGE may provide Seller with written notice of default. Seller shall have one year in which to cure the default during which time the Seller shall pay PGE damages equal to the Lost Energy Value. If Seller is unable to cure the default, PGE may immediately terminate this Agreement as provided in Section 8.3. PGE's resource sufficiency/deficiency position shall have no bearing on PGE's right to terminate the Agreement under this Section 8.2.
- 8.3. In the event of a default hereunder, except as otherwise provided in this Agreement, the non-defaulting party may immediately terminate this Agreement at its sole discretion by delivering written notice to the other Party. In addition, the non-defaulting Party may pursue any and all legal or equitable remedies provided by law or pursuant to this Agreement including damages related to the need to procure replacement power. A termination hereunder shall be effective upon the date of delivery of notice, as provided in Section 20. The rights provided in this Section 8 are cumulative such that the exercise of one or more rights shall not constitute a waiver of any other rights.
- 8.4. If this Agreement is terminated as provided in this Section 8, PGE shall make all payments, within thirty (30) days, that, pursuant to the terms of this Agreement, are owed to Seller as of the time of receipt of notice of default. PGE shall not be required to pay Seller for any Net Output delivered by Seller after such notice of default.
- 8.5. In the event PGE terminates this Agreement pursuant to this Section 8, and Seller wishes to again sell Net Output to PGE following such termination, PGE in its sole discretion may require that Seller shall do so subject to the terms of this Agreement, including but not limited to the Contract Price until the Term of this Agreement (as set forth in Section 2.3) would have run in due course had the Agreement remained in effect. At such time Seller and PGE agree to execute a written document ratifying the terms of this Agreement.
- 8.6. Sections 8.1, 8.4, 8.5, 10, and 19.2 shall survive termination of this Agreement.

SECTION 9: TRANSMISSION CURTAILMENTS

- 9.1. Seller shall give PGE notice as soon as reasonably practicable of any Transmission Curtailment that is likely to affect Seller's ability to deliver any portion of energy scheduled pursuant to Section 4.4 of this Agreement.
- 9.2. If as the result of a Transmission Curtailment, Seller does not deliver any portion of energy (including real-time adjustments), scheduled pursuant to Section 4.4 of this Agreement, Seller shall pay PGE the Transmission Curtailment Replacement Energy Cost for the number of MWh of energy reasonably determined by PGE as the difference between (i) the scheduled energy that would have been delivered to PGE under this Agreement during the period of Transmission Curtailment and (ii) the actual energy, if any, that was delivered to PGE for the period.

Blue Marmot/201 Talbott/139 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

SECTION 10: INDEMNIFICATION AND LIABILITY

- 10.1. Seller agrees to defend, indemnify and hold harmless PGE, its directors, officers, agents, and representatives against and from any and all loss, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with Seller's delivery of electric power to PGE or with the facilities at or prior to the Point of Delivery, or otherwise arising out of this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PGE, Seller or others, excepting to the extent such loss, claim, action or suit may be caused by the negligence of PGE, its directors, officers, employees, agents or representatives.
- 10.2. PGE agrees to defend, indemnify and hold harmless Seller, its directors, officers, agents, and representatives against and from any and all loss, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with PGE's receipt of electric power from Seller or with the facilities at or after the Point of Delivery, or otherwise arising out of this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PGE, Seller or others, excepting to the extent such loss, claim, action or suit may be caused by the negligence of Seller, its directors, officers, employees, agents or representatives.
- 10.3. Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a Party to this Agreement. No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or to the public, nor affect the status of PGE as an independent public utility corporation or Seller as an independent individual or entity.
- 10.4. NEITHER PARTY SHALL BE LIABLE TO THE OTHER FOR SPECIAL, PUNITIVE, INDIRECT OR CONSEQUENTIAL DAMAGES, WHETHER ARISING FROM CONTRACT, TORT (INCLUDING NEGLIGENCE), STRICT LIABILITY OR OTHERWISE.

SECTION 11: INSURANCE

11.1. Prior to the connection of the Facility to PGE's electric system, provided such Facility has a design capacity of 200 kW or more, Seller shall secure and continuously carry for the Term hereof, with an insurance company or companies rated not lower than "B+" by the A. M. Best Company, insurance policies for bodily injury and property damage liability. Such insurance shall include provisions or endorsements naming PGE, it directors, officers and employees as additional insureds; provisions that such insurance is primary insurance with respect to the interest of PGE and that any insurance or self-insurance maintained by PGE is excess and not contributory insurance with the insurance required hereunder; a cross-liability or severability of

Blue Marmot/201 Talbott/140 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

insurance interest clause; and provisions that such policies shall not be canceled or their limits of liability reduced without thirty (30) days' prior written notice to PGE. Initial limits of liability for all requirements under this section shall be \$1,000,000 million single limit, which limits may be required to be increased or decreased by PGE as PGE determines in its reasonable judgment economic conditions or claims experience may warrant.

- 11.2. Prior to the connection of the Facility to PGE's electric system, provided such facility has a design capacity of 200 kW or more, Seller shall secure and continuously carry for the Term hereof, in an insurance company or companies rated not lower than "B+" by the A. M. Best Company, insurance acceptable to PGE against property damage or destruction in an amount not less than the cost of replacement of the Facility. Seller promptly shall notify PGE of any loss or damage to the Facility. Unless the Parties agree otherwise, Seller shall repair or replace the damaged or destroyed Facility, or if the facility is destroyed or substantially destroyed, it may terminate this Agreement. Such termination shall be effective upon receipt by PGE of written notice from Seller. Seller shall waive its insurers' rights of subrogation against PGE regarding Facility property losses.
- 11.3. Prior to the connection of the Facility to PGE's electric system and at all other times such insurance policies are renewed or changed, Seller shall provide PGE with a copy of each insurance policy required under this Section, certified as a true copy by an authorized representative of the issuing insurance company or, at the discretion of PGE, in lieu thereof, a certificate in a form satisfactory to PGE certifying the issuance of such insurance. If Seller fails to provide PGE with copies of such currently effective insurance policies or certificates of insurance, PGE at its sole discretion and without limitation of other remedies, may upon ten (10) days advance written notice by certified or registered mail to Seller either withhold payments due Seller until PGE has received such documents, or purchase the satisfactory insurance and offset the cost of obtaining such insurance from subsequent power purchase payments under this Agreement.

SECTION 12: FORCE MAJEURE

12.1. As used in this Agreement, "Force Majeure" or "an event of Force Majeure" means any cause beyond the reasonable control of the Seller or of PGE which, despite the exercise of due diligence, such Party is unable to prevent or overcome. By way of example, Force Majeure may include but is not limited to acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes, and other labor disturbances, earthquakes, fires, lightning, epidemics, sabotage, restraint by court order or other delay or failure in the performance as a result of any action or inaction on behalf of a public authority which by the exercise of reasonable foresight such Party could not reasonably have been expected to avoid and by the exercise of due diligence, it shall be unable to overcome, subject, in each case, to the requirements of the first sentence of this paragraph. Force Majeure, however, specifically excludes the cost or availability of resources to operate the Facility, changes in market conditions that affect

Blue Marmot/201 Talbott/141 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

the price of energy or transmission, wind or water droughts, and obligations for the payment of money when due.

- 12.2. If either Party is rendered wholly or in part unable to perform its obligation under this Agreement because of an event of Force Majeure, that Party shall be excused from whatever performance is affected by the event of Force Majeure to the extent and for the duration of the Force Majeure, after which such Party shall recommence performance of such obligation, provided that:
- 12.2.1. the non-performing Party, shall, promptly, but in any case within one (1) week after the occurrence of the Force Majeure, give the other Party written notice describing the particulars of the occurrence; and
- 12.2.2. the suspension of performance shall be of no greater scope and of no longer duration than is required by the Force Majeure; and
- 12.2.3. the non-performing Party uses its best efforts to remedy its inability to perform its obligations under this Agreement.
- 12.3. No obligations of either Party which arose before the Force Majeure causing the suspension of performance shall be excused as a result of the Force Majeure.
- 12.4. Neither Party shall be required to settle any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to the Party's best interests.

SECTION 13: SEVERAL OBLIGATIONS

Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership or joint venture or to impose a trust or partnership duty, obligation or liability between the Parties. If Seller includes two or more parties, each such party shall be jointly and severally liable for Seller's obligations under this Agreement.

SECTION 14: CHOICE OF LAW

This Agreement shall be interpreted and enforced in accordance with the laws of the state of Oregon, excluding any choice of law rules which may direct the application of the laws of another jurisdiction.

SECTION 15: PARTIAL INVALIDITY AND PURPA REPEAL

It is not the intention of the Parties to violate any laws governing the subject matter of this Agreement. If any of the terms of the Agreement are finally held or determined to be invalid, illegal or void as being contrary to any applicable law or public policy, all other terms of the Agreement shall remain in effect. If any terms are finally held or determined to be invalid, illegal or void, the Parties shall enter into negotiations concerning the terms affected by such decision for the purpose of achieving conformity with requirements of any applicable law and the intent of the Parties to this Agreement.

Blue Marmot/201 Talbott/142 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

In the event the Public Utility Regulatory Policies Act (PURPA) is repealed, this Agreement shall not terminate prior to the Termination Date, unless such termination is mandated by state or federal law.

SECTION 16: WAIVER

Any waiver at any time by either Party of its rights with respect to a default under this Agreement or with respect to any other matters arising in connection with this Agreement must be in writing, and such waiver shall not be deemed a waiver with respect to any subsequent default or other matter.

SECTION 17: GOVERNMENTAL JURISDICTION AND AUTHORIZATIONS

This Agreement is subject to the jurisdiction of those governmental agencies having control over either Party or this Agreement. Seller shall at all times maintain in effect all local, state and federal licenses, permits and other approvals as then may be required by law for the construction, operation and maintenance of the Facility, and shall provide upon request copies of the same to PGE.

SECTION 18: SUCCESSORS AND ASSIGNS

This Agreement and all of the terms hereof shall be binding upon and inure to the benefit of the respective successors and assigns of the Parties. No assignment hereof by either Party shall become effective without the written consent of the other Party being first obtained and such consent shall not be unreasonably withheld. Notwithstanding the foregoing, either Party may assign this Agreement without the other Party's consent as part of (a) a sale of all or substantially all of the assigning Party's assets, or (b) a merger, consolidation or other reorganization of the assigning Party.

SECTION 19: ENTIRE AGREEMENT

- 19.1. This Agreement supersedes all prior agreements, proposals, representations, negotiations, discussions or letters, whether oral or in writing, regarding PGE's purchase of Net Output from the Facility. No modification of this Agreement shall be effective unless it is in writing and signed by both Parties.
- 19.2. By executing this Agreement, Seller releases PGE from any third party claims related to the Facility, known or unknown, which may have arisen prior to the Effective Date.

SECTION 20: NOTICES

20.1. All notices except as otherwise provided in this Agreement shall be in writing, shall be directed as follows and shall be considered delivered if delivered in person or when deposited in the U.S. Mail, postage prepaid by certified or registered mail and return receipt requested:

 $Blue\ Marmot/201$ Talbott/143 $Schedule\ 201$ $Standard\ Renewable\ Off-System\ Variable\ Power\ Purchase\ Agreement$ $Form\ Effective\ August\ 12,\ 2016$

	To Seller:	Blue Marmot IX LLCc/o EDP Renewables North America LLC;Attention: General Counsel;808 Travis Suite 808Houston, TX 77002	
	with a copy to:		
	To PGE:	Contracts Manager QF Contracts, 3WTC0306 PGE - 121 SW Salmon St. Portland, Oregon 97204	
20.	ir addresses, by pro	may change the person to whom such notices are addressed viding written notices thereof in accordance with this Section REOF, the Parties hereto have caused this Agreement to be a names as of the Effective Date.	n
PGE			
Name Title: ₋	:		
	Marmot IX LLC e Seller)		
Name Title: ₋	:		

Blue Marmot/201 Talbott/144 Schedule 201

Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

EXHIBIT A
DESCRIPTION OF SELLER'S FACILITY

The facility will be a solar PV plant consisting of 38,715 polycrystalline modules

of nominal 335W rating each. Total plant rating will be 12.970 MWdc/10MWac.

Modules will be mounted to single-axis trackers.

Central inverter stations will be located at intermediate points in the PV field.

Modules will be evenly distributed to the inverter stations. The total inverter

nameplate rating will be 10.0MWac. Each inverter will be directly coupled to a

34.5kV step-up transformer. The transformers will be connected to a 34.5kV AC

collection system, which will feed into the plant switchgear.

The plant switchgear will feed a 34.5kV transmission line, which will run overhead

approximately 4.8 miles to the PacifiCorp Mile-Hi Substation.

Inside the Mile-Hi Substation, the transmission line will connect to a new bay

containing a facility-owned 34.5kV/115kV GSU transformer, associated breakers,

switching, bus, and controls.

The facility-owned components at Mile-Hi substation are considered part of the

self-certified qualifying facility.

A-1

1. Generation a. PVSyst (or equivalent) simulation results detail, including but not limited to: 1. Annual MWh (AC) for the first calendar year of commercia ii. Annual degradation factor 0.007 iii. Average 24-hr profile of generation MWh (AC) for each m See tab "Generation" iv. Expected Solar Capacity Factor 0.272442922 V. Maximum annual output (monthly MWh detail) See tab "Generation" iv. Loss Diagram See	Solar Facility Characteristics:	e of project construction and is subject to design finalization			
i. Annual MWh (AC) for the first calendar year of commercii ii. Annual degradation factor iii. Average 24-hr profile of generation MWh (AC) for each m iv. Expected Solar Capacity Factor v. Expected Solar Capaci	1. Generation				
ii. Annual degradation factor iii. Average 24-hr profile of generation MWh (AC) for each m iv. Expected Solar Capacity Factor v. Maximum annual output (monthly MWh detail) v. Loss Diagram See tab "Generation" Seetab "Generation" Seetab "Generat	a. PVSyst (or equivalent) simulation results detail, including but not limited to:				
iii. Average 24-hr profile of generation MWh (AC) for each m iv. Expected Solar Capacity Factor 0.272442922 v. Maximum annual output (monthly MWh detail) See tab "Generation" iv. Loss Diagram See tab "Generation" v. Loss Diagram See tab "Generation" v. Loss Diagram See tab "Generation" 2. Description of Modules: a. Module type Polycrystalline Silicon b. # of modules 38715 c. Max power voltage 37.4v d. Max power current 8.97A e. Max system voltage 1500V f. Total DC system size 12970kW 3. Description of Racking a. Racking i. Type: (fixed tilt, single-axis tracking, or dual-axis tracking, ii. Tilt angle (if fixed-tilt) N/A iii. Azimuth (default = south-facing) South-Facing 4. Description of Inverters 5. Model ABB PVS980-58-1818kVA-6 c. Maximum Power (kW) 600 e. Max. Output Current (A) 1925A f. Rated DC Voltage 1500 g. Rated DC Current h. Maximum Output (kW) 2000 g. Facility AC Capacity Rating 10.0MW h. Inverter loading ratio	i. Annual MWh (AC) for the first calendar year of commercia 23866				
iv. Expected Solar Capacity Factor 0.272442922 v. Maximum annual output (monthly MWh detail) See tab "Generation" iv. Loss Diagram See tab "Generation" 2. Description of Modules: a. Module type Polycrystalline Silicon b. # of modules 38715 c. Max power voltage 37.4v d. Max power current 8.97A e. Max system voltage 1500v f. Total DC system size 12970kW 3. Description of Racking a. Racking i. Type: (fixed tilt, single-axis tracking, or dual-axis tracking, ii. Tilt angle (if fixed-tilt) N/A iii. Azimuth (default = south-facing) South-Facing 4. Description of Inverters 5. Model ABB PVS980-58-1818kVA-6 c. Maximum Power (kW) 2910kW DC d. Operating Voltage (VAC) 600 e. Max. Output Current (A) 1925A f. Rated DC Voltage 1500 g. Rated DC Current h. Maximum Output (kW) 2000 g. Facility AC Capacity Rating 10.0MW h. Inverter loading ratio	ii. Annual degradation factor	0.007			
v. Maximum annual output (monthly MWh detail) v. Loss Diagram 2. Description of Modules: a. Module type b. # of modules c. Max power voltage d. Max power current e. Max system voltage f. Total DC system size a. Racking i. Type: (fixed tilt, single-axis tracking, or dual-axis tracking, ii. Tilt angle (if fixed-tilt) iii. Azimuth (default = south-facing) f. Description of Inverters: a. Number of Inverters b. Model c. Maximum Power (kW) d. Operating Voltage (VAC) e. Max. Output Current (A) f. Rated DC Voltage g. Racking g. Rated DC Current h. Maximum Output (kW) g. Facility AC Capacity Rating 10. Description of Inverter 11. D	iii. Average 24-hr profile of generation MWh (AC) for each m	See tab "Generation"			
iv. Loss Diagram 2. Description of Modules: a. Module type	iv. Expected Solar Capacity Factor	0.272442922			
2. Description of Modules: a. Module type Polycrystalline Silicon b. # of modules 38715 c. Max power voltage 37.4V d. Max power current 8.97A e. Max system voltage 1500V f. Total DC system size 12970kW 3. Description of Racking a. Racking i. Type: (fixed tilt, single-axis tracking, or dual-axis tracking, ii. Tilt angle (if fixed-tilt) N/A iii. Azimuth (default = south-facing) South-Facing 4. Description of Inverters a. Number of Inverters b. Model ABB PVS980-58-1818kVA-6 c. Maximum Power (kW) 2910kW DC d. Operating Voltage (VAC) 600 e. Max. Output Current (A) 1925A f. Rated DC Voltage 5620 g. Rated DC current 1945 h. Maximum Output (kW) 2000 g. Facility AC Capacity Rating 10.0MW h. Inverter loading ratio	v. Maximum annual output (monthly MWh detail)	See tab "Generation"			
a. Module type Polycrystalline Silicon b. # of modules 38715 c. Max power voltage 37.4V d. Max power current 8.97A e. Max system voltage 1500V f. Total DC system size 12970kW 3. Description of Racking a. Racking i. Type: (fixed tilt, single-axis tracking, or dual-axis tracking, ii. Tilt angle (if fixed-tilt) N/A iii. Azimuth (default = south-facing) South-Facing 4. Description of Inverters: a. Number of Inverters 5. Model ABB PVS980-58-1818kVA-6 c. Maximum Power (kW) 2910kW DC d. Operating Voltage (VAC) 600 e. Max. Output Current (A) 1925A f. Rated DC Voltage 56 g. Rated DC Current 1945 h. Maximum Output (kW) 2000 g. Facility AC Capacity Rating 10.0MW h. Inverter loading ratio	iv. Loss Diagram	See tab "Generation"			
b. # of modules 38715 c. Max power voltage 37.4V d. Max power current 8.97A e. Max system voltage 1500V f. Total DC system size 12970kW 3. Description of Racking a. Racking i. Type: (fixed tilt, single-axis tracking, or dual-axis tracking, ii. Tilt angle (if fixed-tilt) South-Facing 4. Description of Inverters: a. Number of Inverters: b. Model ABB PVS980-58-1818kVA-6 c. Maximum Power (kW) 2910kW DC d. Operating Voltage (VAC) 600 e. Max. Output Current (A) 1925A f. Rated DC Voltage 1500 g. Rated DC current 1945 h. Maximum Output (kW) 2000 g. Facility AC Capacity Rating 10.0MW h. Inverter loading ratio 1500v	2. Description of Modules:				
c. Max power voltage 37.4V d. Max power current 8.97A e. Max system voltage 1500V f. Total DC system size 12970kW 3. Description of Racking a. Racking i. Type: (fixed tilt, single-axis tracking, or dual-axis tracking, ii. Tilt angle (if fixed-tilt) N/A iii. Azimuth (default = south-facing) South-Facing 4. Description of Inverters: a. Number of Inverters 5. Model ABB PVS980-58-1818kVA-6 c. Maximum Power (kW) 2910kW DC d. Operating Voltage (VAC) 600 e. Max. Output Current (A) 1925A f. Rated DC Voltage 1500 g. Rated DC current 1945 h. Maximum Output (kW) 2000 g. Facility AC Capacity Rating 10.0MW h. Inverter loading ratio 1297	a. Module type	Polycrystalline Silicon			
d. Max power current8.97Ae. Max system voltage1500Vf. Total DC system size12970kW3. Description of Rackinga. Rackingi. Type: (fixed tilt, single-axis tracking, or dual-axis tracking, ii. Tilt angle (if fixed-tilt)Single-Axis Tracking ii. N/Aiii. Azimuth (default = south-facing)South-Facing4. Description of Inverters:5a. Number of Inverters5b. ModelABB PVS980-58-1818kVA-6c. Maximum Power (kW)2910kW DCd. Operating Voltage (VAC)600e. Max. Output Current (A)1925Af. Rated DC Voltage1500g. Rated DC current1945h. Maximum Output (kW)2000g. Facility AC Capacity Rating10.0MWh. Inverter loading ratio1.297	b. # of modules	38715			
e. Max system voltage 1500V f. Total DC system size 12970kW 3. Description of Racking a. Racking i. Type: (fixed tilt, single-axis tracking, or dual-axis tracking, ii. Tilt angle (if fixed-tilt) N/A iii. Azimuth (default = south-facing) South-Facing 4. Description of Inverters: a. Number of Inverters b. Model ABB PVS980-58-1818kVA-6 c. Maximum Power (kW) 2910kW DC d. Operating Voltage (VAC) 600 e. Max. Output Current (A) 1925A f. Rated DC Voltage 1500 g. Rated DC current 1945 h. Maximum Output (kW) 2000 g. Facility AC Capacity Rating 10.0MW h. Inverter loading ratio 12.97	c. Max power voltage	37.4V			
f. Total DC system size 12970kW 3. Description of Racking a. Racking i. Type: (fixed tilt, single-axis tracking, or dual-axis tracking, ii. Tilt angle (if fixed-tilt) N/A iii. Azimuth (default = south-facing) South-Facing 4. Description of Inverters: a. Number of Inverters b. Model ABB PVS980-58-1818kVA-6 c. Maximum Power (kW) 2910kW DC d. Operating Voltage (VAC) 600 e. Max. Output Current (A) 1925A f. Rated DC Voltage 1500 g. Rated DC current 1945 h. Maximum Output (kW) 2000 g. Facility AC Capacity Rating 10.0MW h. Inverter loading ratio 1297	d. Max power current	8.97A			
3. Description of Racking a. Racking i. Type: (fixed tilt, single-axis tracking, or dual-axis tracking, ii. Tilt angle (if fixed-tilt) iii. Azimuth (default = south-facing) 4. Description of Inverters: a. Number of Inverters 5. Model 6. Maximum Power (kW) 6. Operating Voltage (VAC) 6. Max. Output Current (A) 6. Rated DC Voltage 7. Rated DC Current 8. Maximum Output (kW) 9. Rated DC current 9. Azimum Output (kW) 9. Cool on the standard of the	e. Max system voltage	1500V			
a. Racking i. Type: (fixed tilt, single-axis tracking, or dual-axis tracking, ii. Tilt angle (if fixed-tilt) iii. Azimuth (default = south-facing) 4. Description of Inverters: a. Number of Inverters 5. Model 6. Maximum Power (kW) 7. Maximum Power (kW) 8. Max. Output Current (A) 7. Rated DC Voltage 8. Rated DC current 9. Rated DC current 9. Rated DC current 9. Rated DC current 9. Maximum Output (kW) 9. Cool of the maximum Output (kW) 9. Cool of tilty AC Capacity Rating 9. Inverter loading ratio 9. Inverter loading ratio 9. Single-Axis Tracking 10.0MW 10. N/A 10	f. Total DC system size	12970kW			
i. Type: (fixed tilt, single-axis tracking, or dual-axis tracking, ii. Tilt angle (if fixed-tilt) N/A iii. Azimuth (default = south-facing) Lescription of Inverters: a. Number of Inverters b. Model C. Maximum Power (kW) C. Maximum Power (kW) Description Voltage (VAC) E. Max. Output Current (A) E. Rated DC voltage E. Rated DC current DESCRIPTION DESCRIPTION DESCRIPTION DESCRIPTION DESCRIPTION Single-Axis Tracking N/A South-Facing ABB PVS980-58-1818kVA-6 C. Maximum Power (kW) DESCRIPTION DESCRIPTION	3. Description of Racking				
ii. Tilt angle (if fixed-tilt) iii. Azimuth (default = south-facing) 4. Description of Inverters: a. Number of Inverters b. Model c. Maximum Power (kW) d. Operating Voltage (VAC) e. Max. Output Current (A) f. Rated DC Voltage g. Rated DC current h. Maximum Output (kW) g. Facility AC Capacity Rating h. Inverter loading ratio	a. Racking				
iii. Azimuth (default = south-facing) 4. Description of Inverters: a. Number of Inverters b. Model c. Maximum Power (kW) d. Operating Voltage (VAC) e. Max. Output Current (A) f. Rated DC Voltage g. Rated DC current h. Maximum Output (kW) g. Facility AC Capacity Rating h. Inverter loading ratio	i. Type: (fixed tilt, single-axis tracking, or dual-axis tracking,	Single-Axis Tracking			
4. Description of Inverters: a. Number of Inverters 5. Model ABB PVS980-58-1818kVA-6 c. Maximum Power (kW) 2910kW DC d. Operating Voltage (VAC) 600 e. Max. Output Current (A) 1925A f. Rated DC Voltage 1500 g. Rated DC current 1945 h. Maximum Output (kW) 2000 g. Facility AC Capacity Rating 10.0MW h. Inverter loading ratio 1500	ii. Tilt angle (if fixed-tilt)	N/A			
a. Number of Inverters b. Model C. Maximum Power (kW) C. Maximum Power (kW) C. Operating Voltage (VAC) E. Max. Output Current (A) F. Rated DC Voltage Facility AC Capacity Rating D. Inverter loading ratio ABB PVS980-58-1818kVA-6 ABB PVS980-58-1818kVA-6 600 600 600 600 600 600 600	iii. Azimuth (default = south-facing)	South-Facing			
b. Model c. Maximum Power (kW) 2910kW DC d. Operating Voltage (VAC) 600 e. Max. Output Current (A) f. Rated DC Voltage g. Rated DC current h. Maximum Output (kW) g. Facility AC Capacity Rating h. Inverter loading ratio	4. Description of Inverters:				
c. Maximum Power (kW) d. Operating Voltage (VAC) e. Max. Output Current (A) f. Rated DC Voltage g. Rated DC current h. Maximum Output (kW) g. Facility AC Capacity Rating h. Inverter loading ratio	a. Number of Inverters	5			
d. Operating Voltage (VAC)600e. Max. Output Current (A)1925Af. Rated DC Voltage1500g. Rated DC current1945h. Maximum Output (kW)2000g. Facility AC Capacity Rating10.0MWh. Inverter loading ratio1.297	b. Model	ABB PVS980-58-1818kVA-6			
e. Max. Output Current (A) f. Rated DC Voltage g. Rated DC current h. Maximum Output (kW) g. Facility AC Capacity Rating h. Inverter loading ratio 1925A 1500 2000 10	c. Maximum Power (kW)	2910kW DC			
f. Rated DC Voltage g. Rated DC current h. Maximum Output (kW) g. Facility AC Capacity Rating h. Inverter loading ratio	d. Operating Voltage (VAC)	600			
g. Rated DC current 1945 h. Maximum Output (kW) 2000 g. Facility AC Capacity Rating 10.0MW h. Inverter loading ratio 1.297	e. Max. Output Current (A)	1925A			
h. Maximum Output (kW) g. Facility AC Capacity Rating h. Inverter loading ratio 2000 10.0MW	f. Rated DC Voltage	1500			
g. Facility AC Capacity Rating 10.0MW h. Inverter loading ratio 1.297	g. Rated DC current	1945			
h. Inverter loading ratio	h. Maximum Output (kW)	2000			
	g. Facility AC Capacity Rating	10.0MW			
i. Facility AC rating	h. Inverter loading ratio	1.297			
	i. Facility AC rating	10.0MW			

5. Description of transformers			
Inverter LV-MV			
a. # of transformers	5		
b. Model	ABB PadPlus+		
c. High Voltage Rating	34500		
d. Low Voltage Rating	600		
e. MVA rating	2.0 each, 10.0 total		
f. High voltage connection	Wye-Ground		
g. Low voltage connection	Wye		
· GSU MV-HV			
a. # of transformers	1		
b. Model	ABB 10MVA		
c. High Voltage Rating	115000		
d. Low Voltage Rating	34500		
e. MVA rating	10/12.5 ONAF		
f. High voltage connection	Wye		
g. Low voltage connection	Delta		
6. Description of metering, communications, and monitorin	, and transmit data to Operator and back to PV plant SCADA.		
7. Description of station service requirements	hase at Mile Hi substation for Customer controls equipment.		
8. Description and timeline of interconnection and transmis mission agreements prior to commercial operation date.			
9. Transaction Service Request Number, Interconnection Q ansmission agreements prior to commercial operation date.			

EXHIBIT B REQUIRED FACILITY DOCUMENTS

Sellers Generation Interconnection Agreement

Transmission Service Agreement with PacifiCorp

Purchase option agreement

Conditional Use Permit issued by Lake County

Any additional permits that might be required by Lake County or Oregon Department of Environmental Quality, including access permit, building and electric permits, and storm water prevention permit

FERC Qualifying Facility self-certification

EXHIBIT C START-UP TESTING

VISUAL AND MECHANICAL INSPECTIONS

INVERTER COMMISSIONING

ELECTRICAL OPERATION TESTS

SYSTEM MONITORING VERIFICATION

TRACKER VERIFICATION

INFRARED SCANS

BLOCK TESTING

72-HOUR FUNCTIONAL TEST

GRID MATCH TEST

POWER CHARACTERIZATION

REVENUE METER VERIFICATION

REACTIVE POWER TEST

POWER OUTPUT TEST - PLANT PERFORMANCE AND ACCEPTANCE

EXHIBIT D SCHEDULE

SCHEDULE 201 QUALIFYING FACILITY 10 MW or LESS AVOIDED COST POWER PURCHASE INFORMATION

PURPOSE

To provide information about Standard Avoided Costs and Renewable Avoided Costs, Standard Power Purchase Agreements (PPA) and Negotiated PPAs, power purchase prices and price options for power delivered by a Qualifying Facility (QF) to the Company with nameplate capacity of 10,000 kW (10MW) or less.

AVAILABLE

To owners of QFs making sales of electricity to the Company in the State of Oregon (Seller).

APPLICABLE

For power purchased from small power production or cogeneration facilities that are QFs as defined in 18 Code of Federal Regulations (CFR) Section 292, that meet the eligibility requirements described herein and where the energy is delivered to the Company's system and made available for Company purchase pursuant to a Standard PPA.

ESTABLISHING CREDITWORTHINESS

The Seller must establish creditworthiness prior to service under this schedule. For a Standard PPA, a Seller may establish creditworthiness with a written acknowledgment that it is current on all existing debt obligations and that it was not a debtor in a bankruptcy proceeding within the preceding 24 months. If the Seller is not able to establish creditworthiness, the Seller must provide security deemed sufficient by the Company as set forth in the Standard PPA.

POWER PURCHASE INFORMATION

A Seller may call the Power Production Coordinator at (503) 464-8000 to obtain more information about being a Seller or how to apply for service under this schedule.

PPA

In accordance with terms set forth in this schedule and the Commission's Rules as applicable, the Company will purchase any Energy in excess of station service (power necessary to produce generation) and amounts attributable to conversion losses, which are made available from the Seller.

A Seller must execute a PPA with the Company prior to delivery of power to the Company. The agreement will have a term of up to 20 years as selected by the QF.

A QF with a nameplate capacity rating of 10 MW or less as defined herein may elect the option of a Standard PPA.

PPA (Continued)

Any Seller may elect to negotiate a PPA with the Company. Such negotiation will comply with the requirements of the Federal Energy Regulatory Commission (FERC), and the Commission including the guidelines in Order No. 07-360, and Schedule 202. Negotiations for power purchase pricing will be based on either the filed Standard Avoided Costs or Renewable Avoided Costs in effect at that time.

STANDARD PPA (Nameplate capacity of 10 MW or less)

A Seller choosing a Standard PPA will complete all informational and price option selection requirements in the applicable Standard PPA and submit the executed Agreement to the Company prior to service under this schedule. The Standard PPA is available at www.portlandgeneral.com. The available Standard PPAs are:

- Standard In-System Non-Variable Power Purchase Agreement
- Standard Off-System Non-Variable Power Purchase Agreement
- Standard In-System Variable Power Purchase Agreement
- Standard Off-System Variable Power Purchase Agreement
- Standard Renewable In-System Non-Variable Power Purchase Agreement
- Standard Renewable Off-System Non-Variable Power Purchase Agreement
- Standard Renewable In-System Variable Power Purchase Agreement
- Standard Renewable Off-System Variable Power Purchase Agreement

The Standard PPAs applicable to variable resources are available only to QFs utilizing wind, solar or run of river hydro as the primary motive force.

GUIDELINES FOR 10 MW OR LESS FACILITIES ELECTING STANDARD PPA

To execute the Standard PPA the Seller must complete all of the general project information requested in the applicable Standard PPA.

When all information required in the Standard PPA has been received in writing from the Seller, the Company will respond within 15 business days with a draft Standard PPA.

The Seller may request in writing that the Company prepare a final draft Standard PPA. The Company will respond to this request within 15 business days. In connection with such request, the QF must provide the Company with any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft Standard PPA.

When both parties are in full agreement as to all terms and conditions of the draft Standard PPA, the Company will prepare and forward to the Seller a final executable version of the agreement within 15 business days. Following the Company's execution, an executed copy will be returned to the Seller. Prices and other terms and conditions in the PPA will not be final and binding until the Standard PPA has been executed by both parties.

OFF-SYSTEM PPA

A Seller with a facility that interconnects with an electric system other than the Company's electric system may enter into a PPA with the Company after following the applicable Standard or Negotiated PPA guidelines and making the arrangements necessary for transmission of power to the Company's system.

BASIS FOR POWER PURCHASE PRICE

AVOIDED COST SUMMARY

The power purchase prices are based on either the Company's Standard Avoided Costs or Renewable Avoided Costs in effect at the time the agreement is executed. Avoided Costs are defined in 18 CFR 292.101(6) as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."

Monthly On-Peak prices are included in both the Standard Avoided Costs as listed in Tables 1a, 2a, and 3a and Renewable Avoided Costs as listed in Tables 4a, 5a, and 6a. Monthly Off-Peak prices are included in both the Standard Avoided Costs as listed in Tables 1b, 2b, and 3b and Renewable Avoided Costs as listed in Tables 4b, 5b, and 6b.

ON-PEAK PERIOD

The On-Peak period is 6:00 a.m. until 10:00 p.m., Monday through Saturday.

OFF-PEAK PERIOD

The Off-Peak period is 10:00 p.m. until 6:00 a.m., Monday through Saturday, and all day on Sunday.

Standard Avoided Costs are based on forward market price estimates through the Resource Sufficiency Period, the period of time during which the Company's Standard Avoided Costs are associated with incremental purchases of Energy and capacity from the market. For the Resource Deficiency Period, the Standard Avoided Costs reflect the fully allocated costs of a natural gas fueled combined cycle combustion turbine (CCCT) including fuel and capital costs. The CCCT Avoided Costs are based on the variable cost of Energy plus capitalized Energy costs at a 93% capacity factor based on a natural gas price forecast, with prices modified for shrinkage and transportation costs.

Renewable Avoided Costs are based on forward market price estimates through the Renewable Resource Sufficiency Period, the period of time during which the Company's Renewable Avoided Costs are associated with incremental purchases of energy and capacity from the market. For the Renewable Resource Deficiency Period, the Renewable Avoided Costs reflect the fully allocated costs of a wind plant including capital costs.

PRICING FOR STANDARD PPA

Pricing represents the purchase price per MWh the Company will pay for electricity delivered to a Point of Delivery (POD) within the Company's service territory pursuant to a Standard PPA up to the nameplate rating of the QF in any hour. Any Energy delivered in excess of the nameplate rating will be purchased at the applicable Off-Peak Prices for the selected pricing option.

The Standard PPA pricing will be based on either the Standard or Renewable Avoided Costs in effect at the time the agreement is executed.

The Company will pay the Seller either the Off-Peak Standard Avoided Cost pursuant to Tables 1b, 2b, or 3b or the Off-Peak Renewable Avoided Costs pursuant to Tables 4b, 5b, or 6b for: (a) all Net Output delivered prior to the Commercial Operation Date; (b) all Net Output deliveries greater than Maximum Net Output in any PPA year; (c) any generation subject to and as adjusted by the provisions of Section 4.3 of the Standard PPA; (d) Net Output delivered in the Off-Peak Period; and (e) deliveries above the nameplate capacity in any hour. The Company will pay the Seller either the On-Peak Standard Avoided Cost pursuant to Tables 1a, 2a, or 3a or the On-Peak Renewable Avoided Costs pursuant to Tables 4a, 5a, or 6a for all other Net Output. (See the PPA for defined terms.)

1) Standard Fixed Price Option

The Standard Fixed Price Option is based on Standard Avoided Costs including forecasted natural gas prices. It is available to all QFs.

This option is available for a maximum term of 15 years. Prices will be as established at the time the Standard PPA is executed and will be equal to the Standard Avoided Costs in Tables 1a and 1b, 2a and 2b, or 3a and 3c, depending on the type of QF, effective at execution. QFs using any resource type other than wind and solar are assumed to be Base Load QFs.

Prices paid to the Seller under the Standard Fixed Price Option include adjustments for the capacity contribution of the QF resource type relative to that of the avoided proxy resource. Both the Base Load QF resources (Tables 1a and 1b) and the avoided proxy resource, the basis used to determine Standard Avoided Costs for the Standard Fixed Price Option, are assumed to have a capacity contribution to peak of 100%. The capacity contribution for Wind QF resources (Tables 2a and 2b) is assumed to be 5%. The capacity contribution for Solar QF resources (Tables 3a and 3b) is assumed to be 5%.

Prices paid to the Seller under the Standard Fixed Price Option for Wind QFs (Tables 2a and 2b) include a reduction for the wind integration costs in Table 7. However, if the Wind QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the wind integration charges in Table 7, in addition to the prices listed in Tables 2a and 2b, for a net-zero effect.

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

Sellers with PPAs exceeding 15 years will receive pricing equal to the Mid-C Index Price for all years up to five in excess of the initial 15.

					T.	ABLE 1a						
					Avo	ided Cos	ts					
			St	andard F	ixed Pric	e Option	for Base	Load QF				
				0	n-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	28.21	22.46	15.61	14.71	12.46	16.96	23.96	26.96	24.96	23.71	26.71	31.46
2017	29.96	28.21	24.71	20.96	19.46	20.46	27.96	30.96	29.46	27.71	28.71	33.71
2018	31.71	31.11	28.11	22.13	21.28	21.28	29.93	33.37	30.63	28.61	31.86	35.71
2019	33.94	31.95	27.97	23.70	22.00	23.13	31.67	35.08	33.37	31.38	32.52	38.21
2020	35.74	33.64	29.45	24.95	23.15	24.35	33.34	36.94	35.14	33.04	34.24	40.24
2021	67.43	67.34	65.41	64.69	64.41	64.50	64.61	64.73	64.84	65.48	68.60	68.72
2022	69.01	68.84	68.08	67.13	66.81	66.91	67.04	67.17	67.29	67.83	71.38	71.70
2023	71.95	71.76	70.39	69.19	69.07	69.18	69.31	69.45	69.58	70.12	73.56	73.70
2024	74.17	73.85	72.67	71.29	71.10	71.21	71.35	71.50	71.63	72.20	76.49	76.64
2025	77.19	77.30	75.84	74.88	75.02	75.14	75.30	75.47	75.62	75.80	82.57	82.89
2026	85.18	85.30	82.77	81.28	81.22	81.36	81.56	81.74	81.90	82.36	89.02	88.72
2027	86.85	86.76	85.14	83.12	82.89	83.03	83.00	83.32	83.46	83.97	91.39	91.15
2028	89.32	89.31	87.96	85.46	85.30	85.46	85.31	85.64	85.95	86.65	94.66	93.55
2029	94.06	93.99	91.23	88.74	87.97	88.15	87.71	88.06	88.61	89.34	98.37	98.11
2030	97.60	97.54	94.87	92.62	92.40	92.57	92.61	93.00	93.12	93.68	102.42	102.70
2031	99.56	99.50	96.78	94.48	94.26	94.43	94.47	94.87	94.99	95.56	104.47	104.76
2032	103.85	103.80	100.57	98.18	97.96	98.15	98.23	98.65	98.76	99.36	108.86	109.41
2033	106.56	106.51	103.17	100.72	100.50	100.69	100.78	101.21	101.32	101.93	111.67	112.26
2034	109.12	109.07	105.60	103.10	102.88	103.08	103.17	103.61	103.72	104.35	114.33	114.96
2035	111.55	111.51	107.91	105.35	105.12	105.33	105.43	105.89	105.99	106.63	116.87	117.54
2036	113.85	113.80	110.14	107.53	107.30	107.51	107.60	108.07	108.18	108.83	119.27	119.95
2037	116.50	116.45	112.72	110.06	109.82	110.04	110.14	110.61	110.73	111.39	122.03	122.73
2038	119.08	119.03	115.22	112.51	112.27	112.49	112.59	113.08	113.19	113.87	124.71	125.42
2039	121.47	121.42	117.54	114.77	114.53	114.75	114.85	115.35	115.47	116.15	127.21	127.93
2040	124.25	124.20	120.25	117.43	117.18	117.41	117.51	118.02	118.14	118.84	130.10	130.85
2041	126.72	126.67	122.64	119.76	119.51	119.74	119.85	120.36	120.49	121.20	132.68	133.44

					Т/	ABLE 1b						
						ded Cost	ts					
			Sta	andard F	ixed Price	e Option	for Base	Load QF				
				0	ff-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	25.61	20.71	13.96	11.41	6.31	10.11	15.71	20.96	20.96	21.21	23.46	26.71
2017	25.71	24.21	22.21	15.71	13.71	12.71	19.71	25.21	25.46	24.71	25.71	27.96
2018	26.17	28.12	25.56	19.46	14.68	12.54	19.71	27.04	26.93	25.35	28.20	30.62
2019	29.84	28.09	25.75	18.15	15.81	14.64	22.83	29.26	29.55	28.67	29.84	32.47
2020	31.75	29.88	27.38	19.28	16.79	15.54	24.27	31.12	31.43	30.50	31.75	34.55
2021	28.88	28.79	26.86	26.15	25.87	25.95	26.07	26.19	26.30	26.94	30.06	30.18
2022	29.73	29.56	28.79	27.85	27.53	27.63	27.75	27.88	28.00	28.54	32.09	32.42
2023	31.78	31.59	30.21	29.01	28.90	29.00	29.14	29.27	29.40	29.95	33.38	33.52
2024	33.48	33.16	31.98	30.60	30.41	30.52	30.66	30.81	30.95	31.51	35.80	35.96
2025	35.58	35.69	34.24	33.27	33.42	33.53	33.70	33.86	34.01	34.19	40.97	41.28
2026	42.77	42.89	40.36	38.87	38.81	38.95	39.15	39.34	39.50	39.95	46.62	46.31
2027	43.63	43.54	41.91	39.89	39.66	39.80	39.77	40.09	40.24	40.74	48.16	47.92
2028	45.26	45.25	43.90	41.40	41.23	41.40	41.25	41.58	41.89	42.59	50.60	49.48
2029	49.15	49.08	46.32	43.83	43.06	43.24	42.80	43.15	43.70	44.43	53.46	53.20
2030	51.82	51.76	49.09	46.84	46.62	46.79	46.83	47.22	47.34	47.90	56.64	56.92
2031	52.90	52.84	50.11	47.82	47.59	47.77	47.81	48.21	48.33	48.90	57.81	58.10
2032	56.59	56.54	53.31	50.92	50.70	50.89	50.97	51.39	51.50	52.10	61.60	62.15
2033	58.08	58.03	54.69	52.24	52.02	52.21	52.30	52.73	52.84	53.45	63.19	63.78
2034	59.54	59.50	56.03	53.52	53.30	53.50	53.59	54.04	54.15	54.77	64.76	65.39
2035	61.18	61.14	57.54	54.98	54.75	54.96	55.06	55.52	55.62	56.26	66.50	67.17
2036	62.67	62.62	58.96	56.35	56.12	56.33	56.43	56.89	57.00	57.65	68.09	68.78
2037	64.17	64.12	60.39	57.73	57.49	57.71	57.80	58.28	58.39	59.06	69.69	70.39
2038	65.73	65.69	61.88	59.17	58.93	59.15	59.25	59.73	59.85	60.52	71.37	72.08
2039	67.09	67.04	63.16	60.40	60.15	60.38	60.48	60.98	61.09	61.78	72.83	73.56
2040	68.83	68.78	64.83	62.01	61.76	61.99	62.09	62.60	62.72	63.42	74.68	75.42
2041	70.23	70.17	66.14	63.27	63.02	63.25	63.36	63.87	63.99	64.71	76.19	76.95

					T	ABLE 2a						
					Avoi	ded Cost	ts					
				Standard	d Fixed P	rice Optic	on for Wi	nd QF				
				0	n-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	24.37	18.62	11.77	10.87	8.62	13.12	20.12	23.12	21.12	19.87	22.87	27.62
2017	26.05	24.30	20.80	17.05	15.55	16.55	24.05	27.05	25.55	23.80	24.80	29.80
2018	27.72	27.12	24.12	18.14	17.29	17.29	25.94	29.38	26.64	24.62	27.87	31.72
2019	29.87	27.88	23.90	19.63	17.93	19.06	27.60	31.01	29.30	27.31	28.45	34.14
2020	31.59	29.49	25.30	20.80	19.00	20.20	29.19	32.79	30.99	28.89	30.09	36.09
2021	30.68	30.59	28.66	27.94	27.66	27.75	27.87	27.99	28.10	28.74	31.86	31.98
2022	31.56	31.39	30.62	29.68	29.36	29.46	29.59	29.72	29.84	30.38	33.93	34.25
2023	33.67	33.48	32.11	30.91	30.79	30.90	31.03	31.17	31.30	31.84	35.28	35.42
2024	35.38	35.06	33.88	32.49	32.30	32.42	32.56	32.70	32.84	33.40	37.70	37.85
2025	37.53	37.64	36.18	35.22	35.36	35.48	35.64	35.81	35.96	36.14	42.91	43.23
2026	44.75	44.87	42.35	40.86	40.79	40.94	41.13	41.32	41.48	41.94	48.60	48.29
2027	45.65	45.56	43.93	41.91	41.68	41.82	41.79	42.12	42.26	42.76	50.18	49.94
2028	47.32	47.31	45.96	43.46	43.30	43.46	43.31	43.64	43.95	44.65	52.66	51.55
2029	51.25	51.18	48.43	45.94	45.16	45.34	44.90	45.25	45.80	46.53	55.57	55.30
2030	53.96	53.90	51.23	48.98	48.76	48.93	48.97	49.36	49.48	50.04	58.78	59.06
2031	55.08	55.02	52.29	50.00	49.77	49.95	49.99	50.38	50.51	51.08	59.99	60.28
2032	58.77	58.72	55.49	53.10	52.88	53.07	53.15	53.57	53.68	54.28	63.78	64.33
2033	60.35	60.30	56.96	54.51	54.29	54.49	54.57	55.00	55.11	55.72	65.46	66.05
2034	61.88	61.83	58.36	55.86	55.63	55.84	55.93	56.37	56.48	57.10	67.09	67.72
2035	63.54	63.49	59.90	57.34	57.11	57.32	57.42	57.87	57.98	58.62	68.86	69.53
2036	65.04	65.00	61.33	58.72	58.49	58.70	58.80	59.27	59.38	60.03	70.46	71.15
2037	66.61	66.57	62.83	60.17	59.93	60.15	60.25	60.73	60.84	61.50	72.14	72.84
2038	68.23	68.18	64.37	61.66	61.42	61.64	61.74	62.23	62.34	63.02	73.86	74.57
2039	69.64	69.59	65.71	62.94	62.70	62.92	63.03	63.52	63.64	64.33	75.38	76.11
2040	71.42	71.37	67.41	64.60	64.35	64.58	64.68	65.18	65.30	66.00	77.27	78.01
2041	72.87	72.82	68.79	65.92	65.66	65.90	66.00	66.52	66.64	67.35	78.84	79.59

					TA	ABLE 2b						
						ided Cost	ts					
				Standard	I Fixed P	rice Optic	on for Wi	nd QF				
				0	ff-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	21.77	16.87	10.12	7.57	2.47	6.27	11.87	17.12	17.12	17.37	19.62	22.87
2017	21.80	20.30	18.30	11.80	9.80	8.80	15.80	21.30	21.55	20.80	21.80	24.05
2018	22.18	24.13	21.57	15.47	10.69	8.55	15.72	23.05	22.94	21.36	24.21	26.63
2019	25.77	24.02	21.68	14.08	11.74	10.57	18.76	25.19	25.48	24.60	25.77	28.40
2020	27.60	25.73	23.23	15.13	12.64	11.39	20.12	26.97	27.28	26.35	27.60	30.40
2021	24.65	24.56	22.63	21.92	21.64	21.72	21.84	21.96	22.07	22.71	25.83	25.95
2022	25.42	25.25	24.48	23.54	23.22	23.32	23.44	23.57	23.69	24.23	27.78	28.11
2023	27.39	27.20	25.82	24.62	24.51	24.61	24.75	24.88	25.01	25.56	28.99	29.13
2024	29.01	28.69	27.51	26.13	25.94	26.05	26.19	26.34	26.48	27.04	31.33	31.49
2025	31.02	31.13	29.68	28.71	28.86	28.97	29.14	29.30	29.45	29.63	36.41	36.72
2026	38.12	38.24	35.71	34.22	34.16	34.30	34.50	34.69	34.85	35.30	41.97	41.66
2027	38.89	38.80	37.17	35.15	34.92	35.06	35.03	35.35	35.50	36.00	43.42	43.18
2028	40.43	40.42	39.07	36.57	36.40	36.57	36.42	36.75	37.06	37.76	45.77	44.65
2029	44.23	44.16	41.40	38.91	38.14	38.32	37.88	38.23	38.78	39.51	48.54	48.28
2030	46.80	46.74	44.07	41.82	41.60	41.77	41.81	42.20	42.32	42.88	51.62	51.90
2031	47.78	47.72	44.99	42.70	42.47	42.65	42.69	43.09	43.21	43.78	52.69	52.98
2032	51.38	51.33	48.10	45.71	45.49	45.68	45.76	46.18	46.29	46.89	56.39	56.94
2033	52.77	52.72	49.38	46.93	46.71	46.90	46.99	47.42	47.53	48.14	57.88	58.47
2034	54.12	54.08	50.61	48.10	47.88	48.08	48.17	48.62	48.73	49.35	59.34	59.97
2035	55.66	55.62	52.02	49.46	49.23	49.44	49.54	50.00	50.10	50.74	60.98	61.65
2036	57.04	56.99	53.33	50.72	50.49	50.70	50.80	51.26	51.37	52.02	62.46	63.15
2037	58.43	58.38	54.65	51.99	51.75	51.97	52.06	52.54	52.65	53.32	63.95	64.65
2038	59.88	59.84	56.03	53.32	53.08	53.30	53.40	53.88	54.00	54.67	65.52	66.23
2039	61.13	61.08	57.20	54.44	54.19	54.42	54.52	55.02	55.13	55.82	66.87	67.60
2040	62.75	62.70	58.75	55.93	55.68	55.91	56.01	56.52	56.64	57.34	68.60	69.34
2041	64.04	63.98	59.95	57.08	56.83	57.06	57.17	57.68	57.80	58.52	70.00	70.76

					T	ABLE 3a						
					Avoi	ded Cost	ts					
				Standard	l Fixed P	rice Optic	on for So	lar QF				
				0	n-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	28.21	22.46	15.61	14.71	12.46	16.96	23.96	26.96	24.96	23.71	26.71	31.46
2017	29.96	28.21	24.71	20.96	19.46	20.46	27.96	30.96	29.46	27.71	28.71	33.71
2018	31.71	31.11	28.11	22.13	21.28	21.28	29.93	33.37	30.63	28.61	31.86	35.71
2019	33.94	31.95	27.97	23.70	22.00	23.13	31.67	35.08	33.37	31.38	32.52	38.21
2020	35.74	33.64	29.45	24.95	23.15	24.35	33.34	36.94	35.14	33.04	34.24	40.24
2021	33.98	33.89	31.96	31.24	30.96	31.05	31.16	31.28	31.39	32.03	35.15	35.27
2022	34.92	34.75	33.98	33.04	32.72	32.82	32.94	33.08	33.20	33.74	37.28	37.61
2023	37.09	36.90	35.52	34.32	34.21	34.31	34.44	34.58	34.71	35.26	38.69	38.83
2024	38.86	38.54	37.36	35.98	35.79	35.90	36.04	36.19	36.32	36.88	41.18	41.33
2025	41.08	41.19	39.73	38.77	38.92	39.03	39.19	39.36	39.51	39.69	46.46	46.78
2026	48.37	48.49	45.97	44.48	44.42	44.56	44.75	44.94	45.10	45.56	52.22	51.91
2027	49.34	49.25	47.62	45.61	45.38	45.51	45.48	45.81	45.95	46.45	53.87	53.63
2028	51.08	51.07	49.72	47.22	47.06	47.22	47.07	47.40	47.72	48.41	56.42	55.31
2029	55.08	55.01	52.26	49.77	48.99	49.17	48.73	49.08	49.63	50.36	59.40	59.13
2030	57.87	57.81	55.14	52.89	52.67	52.84	52.88	53.27	53.39	53.95	62.69	62.97
2031	59.07	59.00	56.28	53.98	53.76	53.93	53.98	54.37	54.49	55.06	63.98	64.26
2032	62.83	62.78	59.56	57.16	56.94	57.13	57.21	57.64	57.75	58.34	67.85	68.39
2033	64.49	64.44	61.09	58.64	58.42	58.62	58.70	59.14	59.25	59.86	69.60	70.18
2034	66.10	66.05	62.58	60.08	59.85	60.05	60.14	60.59	60.70	61.32	71.31	71.94
2035	67.84	67.79	64.20	61.64	61.41	61.62	61.71	62.17	62.28	62.92	73.16	73.83
2036	69.43	69.38	65.72	63.11	62.88	63.09	63.19	63.66	63.77	64.42	74.85	75.54
2037	71.08	71.04	67.30	64.64	64.40	64.62	64.72	65.20	65.31	65.97	76.61	77.31
2038	72.78	72.73	68.93	66.22	65.98	66.20	66.30	66.78	66.90	67.57	78.42	79.13
2039	74.28	74.23	70.35	67.58	67.34	67.56	67.67	68.16	68.28	68.97	80.02	80.75
2040	76.15	76.10	72.15	69.33	69.08	69.31	69.42	69.92	70.04	70.74	82.01	82.75
2041	77.69	77.64	73.61	70.74	70.48	70.72	70.82	71.34	71.46	72.17	83.66	84.41

					TA	ABLE 3b						
					Avoi	ded Cost	ts					
				Standard	l Fixed P	rice Optic	on for So	lar QF				
				0	ff-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	25.61	20.71	13.96	11.41	6.31	10.11	15.71	20.96	20.96	21.21	23.46	26.71
2017	25.71	24.21	22.21	15.71	13.71	12.71	19.71	25.21	25.46	24.71	25.71	27.96
2018	26.17	28.12	25.56	19.46	14.68	12.54	19.71	27.04	26.93	25.35	28.20	30.62
2019	29.84	28.09	25.75	18.15	15.81	14.64	22.83	29.26	29.55	28.67	29.84	32.47
2020	31.75	29.88	27.38	19.28	16.79	15.54	24.27	31.12	31.43	30.50	31.75	34.55
2021	28.88	28.79	26.86	26.15	25.87	25.95	26.07	26.19	26.30	26.94	30.06	30.18
2022	29.73	29.56	28.79	27.85	27.53	27.63	27.75	27.88	28.00	28.54	32.09	32.42
2023	31.78	31.59	30.21	29.01	28.90	29.00	29.14	29.27	29.40	29.95	33.38	33.52
2024	33.48	33.16	31.98	30.60	30.41	30.52	30.66	30.81	30.95	31.51	35.80	35.96
2025	35.58	35.69	34.24	33.27	33.42	33.53	33.70	33.86	34.01	34.19	40.97	41.28
2026	42.77	42.89	40.36	38.87	38.81	38.95	39.15	39.34	39.50	39.95	46.62	46.31
2027	43.63	43.54	41.91	39.89	39.66	39.80	39.77	40.09	40.24	40.74	48.16	47.92
2028	45.26	45.25	43.90	41.40	41.23	41.40	41.25	41.58	41.89	42.59	50.60	49.48
2029	49.15	49.08	46.32	43.83	43.06	43.24	42.80	43.15	43.70	44.43	53.46	53.20
2030	51.82	51.76	49.09	46.84	46.62	46.79	46.83	47.22	47.34	47.90	56.64	56.92
2031	52.90	52.84	50.11	47.82	47.59	47.77	47.81	48.21	48.33	48.90	57.81	58.10
2032	56.59	56.54	53.31	50.92	50.70	50.89	50.97	51.39	51.50	52.10	61.60	62.15
2033	58.08	58.03	54.69	52.24	52.02	52.21	52.30	52.73	52.84	53.45	63.19	63.78
2034	59.54	59.50	56.03	53.52	53.30	53.50	53.59	54.04	54.15	54.77	64.76	65.39
2035	61.18	61.14	57.54	54.98	54.75	54.96	55.06	55.52	55.62	56.26	66.50	67.17
2036	62.67	62.62	58.96	56.35	56.12	56.33	56.43	56.89	57.00	57.65	68.09	68.78
2037	64.17	64.12	60.39	57.73	57.49	57.71	57.80	58.28	58.39	59.06	69.69	70.39
2038	65.73	65.69	61.88	59.17	58.93	59.15	59.25	59.73	59.85	60.52	71.37	72.08
2039	67.09	67.04	63.16	60.40	60.15	60.38	60.48	60.98	61.09	61.78	72.83	73.56
2040	68.83	68.78	64.83	62.01	61.76	61.99	62.09	62.60	62.72	63.42	74.68	75.42
2041	70.23	70.17	66.14	63.27	63.02	63.25	63.36	63.87	63.99	64.71	76.19	76.95

PRICING OPTIONS FOR STANDARD PPA (Continued)

2) Renewable Fixed Price Option

The Renewable Fixed Price Option is based on Renewable Avoided Costs. It is available only to Renewable QFs that generate electricity from a renewable energy source that may be used by the Company to comply with the Oregon Renewable Portfolio Standard as set forth in ORS 469A.005 to 469A.210.

This option is available for a maximum term of 15 years. Prices will be as established at the time the Standard PPA is executed and will be equal to the Renewable Avoided Costs in Tables 4a and 4b, 5a and 5b, or 6a and 6b, depending on the type of QF, effective at execution. QFs using any resource type other than wind and solar are assumed to be Base Load QFs.

Sellers will retain all Environmental Attributes generated by the facility during the Renewable Resource Sufficiency Period. A Renewable QF choosing the Renewable Fixed Price Option must cede all RPS Attributes generated by the facility to the Company from the start of the Renewable Resource Deficiency Period through the remainder of the PPA term.

Prices paid to the Seller under the Renewable Fixed Price Option include adjustments for the capacity contribution of the QF resource type relative to that of the avoided proxy resource. Both Wind QF resources (Tables 5a and 5b) and the avoided proxy resource, the basis used to determine Renewable Avoided Costs for the Renewable Fixed Price Option, are assumed to have a capacity contribution to peak of 5%. The capacity contribution for Solar QF resources (Tables 6a and 6b) is assumed to be 5%. The capacity contribution for Base Load QF resources (Tables 4a and 4b) is assumed to be 100%.

The Renewable Avoided Costs during the Renewable Resource Deficiency Period reflect an increase for avoided wind integration costs, shown in Table 7.

Prices paid to the Seller under the Renewable Fixed Price Option for Wind QFs (Tables 5a and 5b) include a reduction for the wind integration costs in Table 7, which cancels out wind integration costs included in the Renewable Avoided Costs during the Renewable Resource Deficiency Period. However, if the Wind QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the wind integration charges in Table 7, in addition to the prices listed in Tables 5a and 5b.

Sellers with PPAs exceeding 15 years will receive pricing equal to the Mid-C Index Price for all years up to five in excess of the initial 15.

					T.	ABLE 4a						
				F	Renewabl	e Avoide	d Costs					
			Rei	newable l	Fixed Price	ce Option	for Base	e Load Q	F			
				0	n-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	28.36	22.61	15.76	14.86	12.61	17.11	24.11	27.11	25.11	23.86	26.86	31.61
2017	30.11	28.36	24.86	21.11	19.61	20.61	28.11	31.11	29.61	27.86	28.86	33.86
2018	31.86	31.26	28.26	22.28	21.43	21.43	30.08	33.52	30.78	28.76	32.01	35.86
2019	34.10	32.11	28.13	23.86	22.16	23.29	31.83	35.24	33.53	31.54	32.68	38.37
2020	115.34	115.32	114.56	115.02	118.22	117.33	117.01	116.89	115.60	114.63	115.47	114.45
2021	117.94	118.18	116.67	117.75	120.59	119.83	119.26	119.77	118.26	117.25	118.55	117.22
2022	120.48	120.36	118.46	120.19	123.17	122.14	121.69	121.65	120.55	119.55	120.98	119.53
2023	123.26	122.83	120.85	122.92	125.37	124.64	124.29	123.92	123.08	121.92	123.63	122.53
2024	124.86	125.01	123.06	125.07	127.80	126.78	126.67	126.41	126.22	123.83	124.83	124.96
2025	127.73	128.05	125.86	128.21	131.66	130.48	129.53	129.66	128.84	126.59	127.76	127.41
2026	130.91	130.58	129.12	131.30	135.76	132.28	132.28	132.69	132.40	129.34	131.17	130.23
2027	133.47	133.03	131.38	133.50	139.48	134.88	134.51	135.95	134.79	131.96	133.26	132.78
2028	135.95	134.91	132.89	136.24	141.79	136.93	137.64	137.65	136.77	134.76	135.84	135.06
2029	138.81	138.57	135.91	139.29	149.30	140.74	140.82	140.82	140.86	137.50	138.32	138.21
2030	141.68	141.39	139.11	142.00	153.18	145.20	143.05	142.93	144.31	140.18	140.75	140.79
2031	144.29	143.79	142.17	145.52	156.10	149.27	145.71	146.65	146.86	143.04	144.15	143.71
2032	146.51	146.00	144.35	147.76	158.51	151.58	147.95	148.91	149.13	145.24	146.37	145.92
2033	149.91	149.40	147.71	151.19	162.18	155.09	151.39	152.37	152.59	148.62	149.77	149.31
2034	152.96	152.43	150.71	154.26	165.46	158.24	154.46	155.46	155.68	151.64	152.81	152.35
2035	155.76	155.22	153.46	157.08	168.50	161.14	157.29	158.31	158.54	154.41	155.60	155.13
2036	158.31	157.76	155.97	159.65	171.26	163.78	159.86	160.90	161.13	156.94	158.15	157.67
2037	161.83	161.27	159.44	163.20	175.07	167.42	163.42	164.48	164.71	160.43	161.67	161.18
2038	164.95	164.38	162.52	166.35	178.45	170.65	166.57	167.65	167.89	163.52	164.79	164.29
2039	168.13	167.55	165.66	169.56	181.89	173.94	169.79	170.89	171.13	166.68	167.97	167.46
2040	171.05	170.46	168.54	172.51	185.04	176.96	172.74	173.85	174.10	169.58	170.89	170.37
2041	174.69	174.08	172.11	176.17	188.98	180.72	176.40	177.55	177.80	173.18	174.52	173.99

					TA	ABLE 4b						
				F	Renewabl	e Avoide	d Costs					
			Rer	newable F	ixed Pric	e Option	for Base	Load Q	F			
				0	ff-Peak F	orecast (\$/MWH)					
				_				-	_			
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	25.76	20.86	14.11	11.56	6.46	10.26	15.86	21.11	21.11	21.36	23.61	26.86
2017	25.86	24.36	22.36	15.86	13.86	12.86	19.86	25.36	25.61	24.86	25.86	28.11
2018	26.32	28.27	25.71	19.61	14.83	12.69	19.86	27.19	27.08	25.50	28.35	30.77
2019	30.00	28.25	25.91	18.31	15.97	14.80	22.99	29.42	29.71	28.83	30.00	32.63
2020	62.76	63.02	64.56	63.31	59.92	60.16	60.45	61.61	62.52	63.74	63.55	63.99
2021	64.93	64.15	65.85	64.48	61.58	61.62	62.27	62.62	63.78	65.82	63.38	65.09
2022	65.85	65.52	67.77	65.49	62.45	62.82	64.33	63.35	65.00	67.04	64.42	66.29
2023	66.70	66.75	69.10	67.28	62.84	64.01	65.40	64.85	66.14	68.41	65.38	67.63
2024	67.25	67.31	70.47	67.09	63.18	65.92	64.75	65.12	66.62	68.68	67.42	68.05
2025	68.62	68.60	71.94	68.08	63.17	66.28	66.12	67.12	67.23	70.19	69.68	69.06
2026	68.95	69.85	72.28	68.56	63.85	67.22	67.05	67.75	67.05	71.12	69.85	69.89
2027	71.31	71.29	73.13	70.34	63.69	68.45	68.79	68.16	68.57	73.22	70.67	71.18
2028	72.28	72.90	75.41	72.10	63.09	69.98	70.15	68.82	70.20	73.79	71.48	73.41
2029	72.78	73.60	76.79	73.50	58.25	70.29	71.37	70.00	71.53	74.58	73.61	74.68
2030	73.91	74.82	78.36	73.64	58.00	70.89	72.02	72.19	72.00	75.99	75.36	76.23
2031	75.51	76.70	79.40	74.00	59.17	70.67	73.55	73.71	72.16	77.24	77.07	76.31
2032	76.76	77.97	80.71	75.23	60.15	71.83	74.76	74.93	73.35	78.52	78.34	77.57
2033	78.46	79.69	82.50	76.89	61.48	73.42	76.42	76.58	74.97	80.25	80.07	79.29
2034	79.97	81.23	84.09	78.37	62.66	74.84	77.89	78.06	76.42	81.80	81.62	80.82
2035	81.52	82.80	85.71	79.88	63.87	76.28	79.39	79.57	77.89	83.38	83.19	82.38
2036	82.86	84.17	87.13	81.20	64.93	77.54	80.70	80.88	79.18	84.76	84.57	83.74
2037	84.69	86.03	89.05	83.00	66.36	79.25	82.49	82.67	80.93	86.63	86.44	85.59
2038	86.33	87.69	90.77	84.60	67.64	80.78	84.08	84.26	82.49	88.30	88.11	87.24
2039	87.99	89.38	92.52	86.23	68.95	82.34	85.70	85.89	84.08	90.01	89.81	88.92
2040	89.45	90.85	94.05	87.66	70.09	83.70	87.12	87.31	85.47	91.49	91.29	90.39
2041	91.42	92.86	96.13	89.59	71.63	85.55	89.04	89.24	87.36	93.51	93.31	92.39

					T.	ABLE 5a						
				F	Renewabl	e Avoide	d Costs					
				Renewab	le Fixed F	Price Opt	ion for W	ind QF				
				0	n-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	24.52	18.77	11.92	11.02	8.77	13.27	20.27	23.27	21.27	20.02	23.02	27.77
2017	26.20	24.45	20.95	17.20	15.70	16.70	24.20	27.20	25.70	23.95	24.95	29.95
2018	27.87	27.27	24.27	18.29	17.44	17.44	26.09	29.53	26.79	24.77	28.02	31.87
2019	30.03	28.04	24.06	19.79	18.09	19.22	27.76	31.17	29.46	27.47	28.61	34.30
2020	75.38	75.37	74.61	75.06	78.26	77.37	77.05	76.93	75.64	74.67	75.51	74.49
2021	77.10	77.33	75.83	76.90	79.75	78.99	78.41	78.92	77.41	76.40	77.70	76.38
2022	78.85	78.72	76.82	78.56	81.53	80.51	80.05	80.02	78.92	77.92	79.34	77.90
2023	80.71	80.27	78.29	80.37	82.82	82.08	81.73	81.37	80.53	79.36	81.08	79.97
2024	81.74	81.89	79.93	81.95	84.68	83.66	83.55	83.28	83.10	80.71	81.71	81.84
2025	83.64	83.97	81.78	84.13	87.57	86.40	85.44	85.57	84.75	82.51	83.68	83.32
2026	85.97	85.64	84.18	86.37	90.82	87.34	87.34	87.75	87.46	84.40	86.23	85.29
2027	87.67	87.23	85.57	87.69	93.67	89.07	88.71	90.15	88.99	86.16	87.45	86.98
2028	89.26	88.22	86.20	89.55	95.10	90.24	90.95	90.96	90.08	88.07	89.15	88.37
2029	91.22	90.98	88.32	91.70	101.72	93.16	93.23	93.23	93.28	89.92	90.73	90.62
2030	93.17	92.88	90.60	93.49	104.67	96.69	94.54	94.42	95.80	91.67	92.24	92.28
2031	94.84	94.34	92.72	96.07	106.65	99.82	96.26	97.20	97.42	93.59	94.70	94.26
2032	96.40	95.90	94.24	97.65	108.40	101.47	97.85	98.80	99.02	95.13	96.26	95.82
2033	98.55	98.03	96.34	99.82	110.81	103.72	100.02	101.00	101.22	97.25	98.40	97.95
2034	100.44	99.91	98.19	101.74	112.94	105.72	101.94	102.94	103.17	99.12	100.29	99.83
2035	102.38	101.85	100.09	103.71	115.13	107.76	103.92	104.93	105.16	101.04	102.23	101.76
2036	104.06	103.51	101.72	105.40	117.01	109.53	105.61	106.65	106.88	102.69	103.90	103.42
2037	106.37	105.81	103.99	107.74	119.61	111.96	107.96	109.02	109.26	104.97	106.21	105.72
2038	108.42	107.86	105.99	109.82	121.92	114.12	110.05	111.12	111.37	107.00	108.26	107.76
2039	110.52	109.94	108.04	111.95	124.27	116.33	112.17	113.27	113.52	109.07	110.36	109.85
2040	112.32	111.73	109.81	113.77	126.31	118.23	114.00	115.12	115.37	110.85	112.16	111.64
2041	114.83	114.23	112.26	116.31	129.12	120.86	116.55	117.69	117.95	113.32	114.66	114.13

					T	ABLE 5b						
				R	Renewabl	e Avoide	d Costs					
			F	Renewabl	e Fixed F	Price Opt	ion for W	ind QF				
				0	ff-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	21.92	17.02	10.27	7.72	2.62	6.42	12.02	17.27	17.27	17.52	19.77	23.02
2017	21.95	20.45	18.45	11.95	9.95	8.95	15.95	21.45	21.70	20.95	21.95	24.20
2018	22.33	24.28	21.72	15.62	10.84	8.70	15.87	23.20	23.09	21.51	24.36	26.78
2019	25.93	24.18	21.84	14.24	11.90	10.73	18.92	25.35	25.64	24.76	25.93	28.56
2020	58.61	58.87	60.41	59.16	55.77	56.01	56.30	57.46	58.37	59.59	59.40	59.84
2021	60.70	59.92	61.62	60.25	57.35	57.39	58.04	58.39	59.55	61.59	59.15	60.86
2022	61.54	61.21	63.46	61.18	58.14	58.51	60.02	59.04	60.69	62.73	60.11	61.98
2023	62.31	62.36	64.71	62.89	58.45	59.62	61.01	60.46	61.75	64.02	60.99	63.24
2024	62.78	62.84	66.00	62.62	58.71	61.45	60.28	60.65	62.15	64.21	62.95	63.58
2025	64.06	64.04	67.38	63.52	58.61	61.72	61.56	62.56	62.67	65.63	65.12	64.50
2026	64.30	65.20	67.63	63.91	59.20	62.57	62.40	63.10	62.40	66.47	65.20	65.24
2027	66.57	66.55	68.39	65.60	58.95	63.71	64.05	63.42	63.83	68.48	65.93	66.44
2028	67.45	68.07	70.58	67.27	58.26	65.15	65.32	63.99	65.37	68.96	66.65	68.58
2029	67.86	68.68	71.87	68.58	53.33	65.37	66.45	65.08	66.61	69.66	68.69	69.76
2030	68.89	69.80	73.34	68.62	52.98	65.87	67.00	67.17	66.98	70.97	70.34	71.21
2031	70.39	71.58	74.28	68.88	54.05	65.55	68.43	68.59	67.04	72.12	71.95	71.19
2032	71.55	72.76	75.50	70.02	54.94	66.62	69.55	69.72	68.14	73.31	73.13	72.36
2033	73.15	74.38	77.19	71.58	56.17	68.11	71.11	71.27	69.66	74.94	74.76	73.98
2034	74.55	75.81	78.67	72.95	57.24	69.42	72.47	72.64	71.00	76.38	76.20	75.40
2035	76.00	77.28	80.19	74.36	58.35	70.76	73.87	74.05	72.37	77.86	77.67	76.86
2036	77.23	78.54	81.50	75.57	59.30	71.91	75.07	75.25	73.55	79.13	78.94	78.11
2037	78.95	80.29	83.31	77.26	60.62	73.51	76.75	76.93	75.19	80.89	80.70	79.85
2038	80.48	81.84	84.92	78.75	61.79	74.93	78.23	78.41	76.64	82.45	82.26	81.39
2039	82.03	83.42	86.56	80.27	62.99	76.38	79.74	79.93	78.12	84.05	83.85	82.96
2040	83.37	84.77	87.97	81.58	64.01	77.62	81.04	81.23	79.39	85.41	85.21	84.31
2041	85.23	86.67	89.94	83.40	65.44	79.36	82.85	83.05	81.17	87.32	87.12	86.20

					T.	ABLE 6a						
				F	Renewabl	e Avoide	d Costs					
				Renewab	le Fixed F	Price Opt	ion for S	olar QF				
				0	n-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	28.36	22.61	15.76	14.86	12.61	17.11	24.11	27.11	25.11	23.86	26.86	31.61
2017	30.11	28.36	24.86	21.11	19.61	20.61	28.11	31.11	29.61	27.86	28.86	33.86
2018	31.86	31.26	28.26	22.28	21.43	21.43	30.08	33.52	30.78	28.76	32.01	35.86
2019	34.10	32.11	28.13	23.86	22.16	23.29	31.83	35.24	33.53	31.54	32.68	38.37
2020	78.62	78.60	77.84	78.30	81.50	80.60	80.29	80.17	78.88	77.91	78.74	77.73
2021	80.39	80.63	79.12	80.20	83.04	82.28	81.71	82.22	80.71	79.70	81.00	79.67
2022	82.21	82.08	80.18	81.92	84.89	83.87	83.41	83.38	82.27	81.27	82.70	81.25
2023	84.12	83.69	81.71	83.78	86.23	85.50	85.15	84.78	83.94	82.78	84.50	83.39
2024	85.22	85.37	83.41	85.43	88.16	87.14	87.03	86.76	86.58	84.19	85.19	85.32
2025	87.19	87.52	85.33	87.68	91.12	89.95	88.99	89.12	88.30	86.06	87.23	86.87
2026	89.59	89.26	87.80	89.99	94.44	90.96	90.96	91.37	91.08	88.02	89.85	88.91
2027	91.36	90.92	89.26	91.39	97.36	92.76	92.40	93.84	92.68	89.85	91.14	90.67
2028	93.02	91.98	89.96	93.31	98.86	94.00	94.71	94.72	93.84	91.84	92.91	92.13
2029	95.05	94.81	92.15	95.53	105.55	96.99	97.06	97.06	97.11	93.75	94.56	94.45
2030	97.08	96.79	94.51	97.40	108.58	100.60	98.45	98.33	99.71	95.58	96.15	96.19
2031	98.83	98.33	96.70	100.05	110.63	103.81	100.25	101.19	101.40	97.58	98.69	98.25
2032	100.47	99.96	98.30	101.71	112.47	105.53	101.91	102.87	103.08	99.20	100.32	99.88
2033	102.68	102.16	100.47	103.95	114.95	107.86	104.16	105.14	105.36	101.38	102.53	102.08
2034	104.66	104.13	102.41	105.96	117.16	109.94	106.16	107.16	107.38	103.34	104.51	104.05
2035	106.68	106.15	104.39	108.01	119.43	112.06	108.21	109.23	109.46	105.34	106.53	106.06
2036	108.44	107.90	106.11	109.79	121.40	113.91	110.00	111.04	111.27	107.08	108.29	107.81
2037	110.84	110.28	108.46	112.21	124.08	116.43	112.43	113.49	113.73	109.44	110.68	110.19
2038	112.98	112.41	110.55	114.38	126.47	118.68	114.60	115.68	115.92	111.55	112.82	112.32
2039	115.16	114.58	112.68	116.59	128.92	120.97	116.81	117.91	118.16	113.71	115.00	114.49
2040	117.06	116.47	114.54	118.51	131.04	122.96	118.74	119.86	120.11	115.58	116.89	116.37
2041	119.65	119.05	117.07	121.13	133.94	125.68	121.37	122.51	122.76	118.14	119.48	118.95

					TA	ABLE 6b						
				R	Renewable	e Avoide	d Costs					
			F	Renewabl	e Fixed F	Price Opt	ion for So	olar QF				
				0	ff-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	25.76	20.86	14.11	11.56	6.46	10.26	15.86	21.11	21.11	21.36	23.61	26.86
2017	25.86	24.36	22.36	15.86	13.86	12.86	19.86	25.36	25.61	24.86	25.86	28.11
2018	26.32	28.27	25.71	19.61	14.83	12.69	19.86	27.19	27.08	25.50	28.35	30.77
2019	30.00	28.25	25.91	18.31	15.97	14.80	22.99	29.42	29.71	28.83	30.00	32.63
2020	62.76	63.02	64.56	63.31	59.92	60.16	60.45	61.61	62.52	63.74	63.55	63.99
2021	64.93	64.15	65.85	64.48	61.58	61.62	62.27	62.62	63.78	65.82	63.38	65.09
2022	65.85	65.52	67.77	65.49	62.45	62.82	64.33	63.35	65.00	67.04	64.42	66.29
2023	66.70	66.75	69.10	67.28	62.84	64.01	65.40	64.85	66.14	68.41	65.38	67.63
2024	67.25	67.31	70.47	67.09	63.18	65.92	64.75	65.12	66.62	68.68	67.42	68.05
2025	68.62	68.60	71.94	68.08	63.17	66.28	66.12	67.12	67.23	70.19	69.68	69.06
2026	68.95	69.85	72.28	68.56	63.85	67.22	67.05	67.75	67.05	71.12	69.85	69.89
2027	71.31	71.29	73.13	70.34	63.69	68.45	68.79	68.16	68.57	73.22	70.67	71.18
2028	72.28	72.90	75.41	72.10	63.09	69.98	70.15	68.82	70.20	73.79	71.48	73.41
2029	72.78	73.60	76.79	73.50	58.25	70.29	71.37	70.00	71.53	74.58	73.61	74.68
2030	73.91	74.82	78.36	73.64	58.00	70.89	72.02	72.19	72.00	75.99	75.36	76.23
2031	75.51	76.70	79.40	74.00	59.17	70.67	73.55	73.71	72.16	77.24	77.07	76.31
2032	76.76	77.97	80.71	75.23	60.15	71.83	74.76	74.93	73.35	78.52	78.34	77.57
2033	78.46	79.69	82.50	76.89	61.48	73.42	76.42	76.58	74.97	80.25	80.07	79.29
2034	79.97	81.23	84.09	78.37	62.66	74.84	77.89	78.06	76.42	81.80	81.62	80.82
2035	81.52	82.80	85.71	79.88	63.87	76.28	79.39	79.57	77.89	83.38	83.19	82.38
2036	82.86	84.17	87.13	81.20	64.93	77.54	80.70	80.88	79.18	84.76	84.57	83.74
2037	84.69	86.03	89.05	83.00	66.36	79.25	82.49	82.67	80.93	86.63	86.44	85.59
2038	86.33	87.69	90.77	84.60	67.64	80.78	84.08	84.26	82.49	88.30	88.11	87.24
2039	87.99	89.38	92.52	86.23	68.95	82.34	85.70	85.89	84.08	90.01	89.81	88.92
2040	89.45	90.85	94.05	87.66	70.09	83.70	87.12	87.31	85.47	91.49	91.29	90.39
2041	91.42	92.86	96.13	89.59	71.63	85.55	89.04	89.24	87.36	93.51	93.31	92.39

WIND INTEGRATION

TABLE 7	
Wind Integration	
Year	Cost
2015	3.77
2016	3.84
2017	3.91
2018	3.99
2019	4.07
2020	4.15
2021	4.23
2022	4.31
2023	4.39
2024	4.47
2025	4.56
2026	4.65
2027	4.74
2028	4.83
2029	4.92
2030	5.02
2031	5.12
2032	5.21
2033	5.31
2034	5.42
2035	5.52
2036	5.63
2037	5.74
2038	5.85
2039	5.96
2040	6.08

MONTHLY SERVICE CHARGE

Each separately metered QF not associated with a retail Customer account will be charged \$10.00 per month.

INSURANCE REQUIREMENTS

The following insurance requirements are applicable to Sellers with a Standard PPA:

- 1) QFs with nameplate capacity ratings greater than 200 kW are required to secure and maintain a prudent amount of general liability insurance. The Seller must certify to the Company that it is maintaining general liability insurance coverage for each QF at prudent amounts. A prudent amount will be deemed to mean liability insurance coverage for both bodily injury and property damage liability in the amount of not less than \$1,000,000 each occurrence combined single limit, which limits may be required to be increased or decreased by the Company as the Company determines in its reasonable judgment, that economic conditions or claims experience may warrant.
- Such insurance will include an endorsement naming the Company as an additional insured insofar as liability arising out of operations under this schedule and a provision that such liability policies will not be canceled or their limits reduced without 30 days' written notice to the Company. The Seller will furnish the Company with certificates of insurance together with the endorsements required herein. The Company will have the right to inspect the original policies of such insurance.
- 3) QFs with a design capacity of 200 kW or less are encouraged to pursue liability insurance on their own. The Oregon Public Utility Commission in Order No. 05-584 determined that it is inappropriate to require QFs that have a design capacity of 200 kW or less to obtain general liability insurance.

TRANSMISSION AGREEMENTS

If the QF is located outside the Company's service territory, the Seller is responsible for the transmission of power at its cost to the Company's service territory.

INTERCONNECTION REQUIREMENTS

Except as otherwise provided in a generation Interconnection Agreement between the Company and Seller, if the QF is located within the Company's service territory, switching equipment capable of isolating the QF from the Company's system will be accessible to the Company at all times. At the Company's option, the Company may operate the switching equipment described above if, in the sole opinion of the Company, continued operation of the QF in connection with the utility's system may create or contribute to a system emergency.

INTERCONNECTION REQUIREMENTS (Continued)

The QF owner interconnecting with the Company's distribution system must comply with all requirements for interconnection as established pursuant to Commission rule, in the Company's Rules and Regulations (Rule C) or the Company's Interconnection Procedures contained in its FERC Open Access Transmission Tariff (OATT), as applicable. The Seller will bear full responsibility for the installation and safe operation of the interconnection facilities.

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE PRICING UNDER THE STANDARD PPA

A QF will be eligible to receive pricing under the Standard PPA if the nameplate capacity of the QF, together with any other electric generating facility using the same motive force, owned or controlled by the Same Person(s) or Affiliated Person(s), and located at the Same Site, does not exceed 10 MW. A Community-Based or Family-Owned QF is exempt from these restrictions.

Definition of Community-Based

- a. A community project (or a community sponsored project) must have a recognized and established organization located within the county of the project or within 50 miles of the project that has a genuine role in helping the project be developed and must have some not insignificant continuing role with or interest in the project after it is completed and placed in service.
- b. After excluding the passive investor whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit, the equity (ownership) interests in a community sponsored project must be owned in substantial percentage (80 percent or more) by the following persons (individuals and entities): (i) the sponsoring organization, or its controlled affiliates; (ii) members of the sponsoring organization (if it is a membership organization) or owners of the sponsorship organization (if it is privately owned); (iii) persons who live in the county in which the project is located or who live a county adjoining the county in which the project is located; or (iv) units of local government, charities, or other established nonprofit organizations active either in the county in which the project is located or active in a county adjoining the county in which the project is located.

Definition of Family-Owned

After excluding the ownership interest of the passive investor whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit, five or fewer individuals own 50 percent or more of the equity of the project entity, or fifteen or fewer individuals own 90 percent or more of the project entity. A "look through" rule applies to closely held entities that hold the project entity, so that equity held by LLCs, trusts, estates, corporations, partnerships or other similar entities is considered held by the equity owners of the look through entity. An individual is a natural person. In counting to five or fifteen, spouses or children of an equity owner of the project owner who also have an equity interest are aggregated and counted as a single individual.

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE PRICING UNDER THE STANDARD PPA (Continued)

Definition of Person(s) or Affiliated Person(s)

As used above, the term "Same Person(s)" or "Affiliated Person(s)" means a natural person or persons or any legal entity or entities sharing common ownership, management or acting jointly or in concert with or exercising influence over the policies or actions of another person or entity. However, two facilities will not be held to be owned or controlled by the Same Person(s) or Affiliated Person(s) solely because they are developed by a single entity.

Furthermore, two facilities will not be held to be owned or controlled by the Same Person(s) or Affiliated Person(s) if such common person or persons is a "passive investor" whose ownership interest in the QF is primarily related to utilizing production tax credits, green tag values and MACRS depreciation as the primary ownership benefit and the facilities at issue are independent family-owned or community-based projects. A unit of Oregon local government may also be a "passive investor" in a community-based project if the local governmental unit demonstrates that it will not have an equity ownership interest in or exercise any control over the management of the QF and that its only interest is a share of the cash flow from the QF, which share will not exceed 20%. The 20% cash flow share limit may only be exceeded for good cause shown and only with the prior approval of the Commission.

Definition of Same Site

For purposes of the foregoing, generating facilities are considered to be located at the same site as the QF for which qualification for pricing under the Standard PPA is sought if they are located within a five-mile radius of any generating facilities or equipment providing fuel or motive force associated with the QF for which qualification for pricing under the Standard PPA is sought.

Definition of Shared Interconnection and Infrastructure

QFs otherwise meeting the above-described separate ownership test and thereby qualified for entitlement to pricing under the Standard PPA will not be disqualified by utilizing an interconnection or other infrastructure not providing motive force or fuel that is shared with other QFs qualifying for pricing under the Standard PPA so long as the use of the shared interconnection complies with the interconnecting utility's safety and reliability standards, interconnection agreement requirements and Prudent Electrical Practices as that term is defined in the interconnecting utility's approved Standard PPA.

OTHER DEFINITIONS

Mid-C Index Price

As used in this schedule, the daily Mid-C Index Price shall be the Day Ahead Intercontinental Exchange ("ICE") for the bilateral OTC market for energy at the Mid-C Physical for Average

OTHER DEFINITIONS (Continued)

On-Peak Power and Average Off-Peak Power found on the following website: https://www.theice.com/products/OTC/Physical-Energy/Electricity. In the event ICE no longer publishes this index, PGE and the Seller agree to select an alternative successor index representative of the Mid-C trading hub.

Definition of RPS Attributes

As used in this schedule, RPS Attributes means all attributes related to the Net Output generated by the Facility that are required in order to provide PGE with "qualifying electricity," as that term is defined in Oregon's Renewable Portfolio Standard Act, Ore. Rev. Stat. 469A.010, in effect at the time of execution of this Agreement. RPS Attributes do not include Environmental Attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity and not needed to ensure that there are zero net emissions associated with the generation of electricity.

Definition of Environmental Attributes

As used in this schedule, Environmental Attributes shall mean any and all claims, credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical, or other substance to the air, soil or water. Environmental Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil, or water such as (subject to the foregoing) sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; and (2) any avoided emissions of carbon dioxide (CO2), methane (CH4), and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere.

Definition of Resource Sufficiency Period

This is the period from the current year through 2020.

Definition of Resource Deficiency Period

This is the period from 2021 through 2034.

Definition of Renewable Resource Sufficiency Period

This is the period from the current year through 2019.

Definition of Renewable Resource Deficiency Period

This is the period from 2020 through 2034.

SCHEDULE 201 (Concluded)

DISPUTE RESOLUTION

Upon request, the QF will provide the purchasing utility with documentation verifying the ownership, management and financial structure of the QF in reasonably sufficient detail to allow the utility to make an initial determination of whether or not the QF meets the above-described criteria for entitlement to pricing under the Standard PPA.

The QF may present disputes to the Commission for resolution using the following process:

The QF may file a complaint asking the Commission to adjudicate disputes regarding the formation of the standard contract. The QF may not file such a complaint during any 15-day period in which the utility has the obligation to respond, but must wait until the 15-day period has passed.

The utility may respond to the complaint within ten days of service.

The Commission will limit its review to the issues identified in the complaint and response, and utilize a process similar to the arbitration process adopted to facilitate the execution of interconnection agreements among telecommunications carriers. See OAR 860, Division 016. The administrative law judge will not act as an arbitrator.

SPECIAL CONDITIONS

- 1. Delivery of energy by Seller will be at a voltage, phase, frequency, and power factor as specified by the Company.
- 2. If the Seller also receives retail Electricity Service from the Company at the same location, any payments under this schedule will be credited to the Seller's retail Electricity Service bill. At the option of the Customer, any net credit over \$10.00 will be paid by check to the Customer.
- 3. Unless required by state or federal law, if the 1978 Public Utility Regulatory Policies Act (PURPA) is repealed, PPAs entered into pursuant to this schedule will not terminate prior to the Standard or Negotiated PPA's termination date.

TERM OF AGREEMENT

Not less than one year and not to exceed 20 years.

Blue Marmot/201 Talbott/174 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

STANDARD RENEWABLE OFF-SYSTEM VARIABLE POWER PURCHASE AGREEMENT

THIS AGREEMENT is between <u>Blue Marmot VII LLC</u> ("Seller") and Portland General Electric Company ("PGE") (hereinafter each a "Party" or collectively, "Parties") and is effective upon execution by both Parties ("Effective Date").

RECITALS

Seller intends to construct, own, operate and maintain a <u>Solar</u> facility for the generation of electric power located in <u>Lake (W-120.333, N 42.117)</u> County, <u>Oregon</u> with a Nameplate Capacity Rating of <u>10,000</u> kilowatt ("kW"), as further described in Exhibit A ("Facility"); and

Seller intends to operate the Facility as a "Qualifying Facility," as such term is defined in Section 3.1.3, below.

Seller shall sell and PGE shall purchase the entire Net Output, as such term is defined in Section 1.21, below, from the Facility in accordance with the terms and conditions of this Agreement.

AGREEMENT

NOW, THEREFORE, the Parties mutually agree as follows:

SECTION 1: DEFINITIONS

When used in this Agreement, the following terms shall have the following meanings:

- 1.1. "As-built Supplement" means the supplement to Exhibit A provided by Seller in accordance with Section 4.3 following completion of construction of the Facility, describing the Facility as actually built.
- 1.2. "Base Hours" is defined as the total number of hours in each Contract Year (8,760 or 8,784 for leap year)
- 1.3. "Billing Period" means from the start of the first day of each calendar month to the end of the last day of each calendar month.
- 1.4. "Cash Escrow" means an agreement by two parties to place money into the custody of a third party for delivery to a grantee only after the fulfillment of the conditions specified.
- 1.5. "Commercial Operation Date" means the date that the Facility is deemed by PGE to be fully operational and reliable. PGE may, at its discretion require, among other things, that all of the following events have occurred:
- 1.5.1. (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from a Licensed

Blue Marmot/201 Talbott/175 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

Professional Engineer ("LPE") acceptable to PGE in its reasonable judgment stating that the Facility is able to generate electric power reliably in accordance with the terms and conditions of this Agreement (certifications required under this Section 1.5 can be provided by one or more LPEs);

- 1.5.2. Start-Up Testing of the Facility has been completed in accordance with Section 1.36;
- 1.5.3. (facilities with nameplate under 500 kW exempt from following requirement) After PGE has received notice of completion of Start-Up Testing, PGE has received a certificate addressed to PGE from an LPE stating that the Facility has operated for testing purposes under this Agreement and was continuously mechanically available for operation for a minimum of 120 hours. The Facility must provide ten (10) working days written notice to PGE prior to the start of the initial testing period. If the mechanical availability of the Facility is interrupted during this initial testing period or any subsequent testing period, the Facility shall promptly start a new Test Period and provide PGE forty-eight (48) hours written notice prior to the start of such testing period;
- 1.5.4. (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from an LPE stating that all required interconnection facilities have been constructed and all required interconnection tests have been completed;
- 1.5.5. (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from an LPE stating that Seller has obtained all Required Facility Documents and, if requested by PGE in writing, has provided copies of any or all such requested Required Facility Documents;
- 1.5.6. PGE has received a copy of the executed Generation Interconnection and Transmission Agreements.
- 1.6. "Contract Price" means the applicable price, including on-peak and off-peak prices, as specified in the Schedule.
- 1.7. "Contract Year" means each twelve (12) month period commencing upon the Commercial Operation Date or its anniversary during the Term, except the final Contract Year will be the period from the last anniversary of the Commercial Operation Date during the Term until the end of the Term.
 - 1.8. "Effective Date" has the meaning set forth in Section 2.1.
- 1.9. "Environmental Attributes" shall mean any and all claims, credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical or other substance to the air, soil or water. Environmental Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil or water such as (subject to the foregoing) sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; and (2) any avoided emissions of carbon dioxide (CO2), methane (CH4), and other greenhouse gasses (GHGs) that have been determined by the United Nations

Blue Marmot/201 Talbott/176 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

Intergovernmental Panel on Climate Change to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere.

- 1.10. "Facility" has the meaning set forth in the Recitals.
- 1.11. "Generation Interconnection Agreement" means an agreement governing the interconnection of the Facility with **Pacificorp** electric system.
- 1.12. "Generation Unit" means each separate electrical generator that contributes toward Nameplate Capacity Rating included in Exhibit A. For solar facilities, a generating unit is a complete solar electrical generation system within the Facility that is able to generate and deliver energy to the Point of Delivery independent of other Generation Units within the same Facility.
- 1.13. "Letter of Credit" means an engagement by a bank or other person made at the request of a customer that the issuer will honor drafts or other demands for payment upon compliance with the conditions specified in the letter of credit.
- 1.14. "Licensed Professional Engineer" or "LPE" means a person who is licensed to practice engineering in the state where the Facility is located, who has no economic relationship, association, or nexus with the Seller, and who is not a representative of a consulting engineer, contractor, designer or other individual involved in the development of the Facility, or of a manufacturer or supplier of any equipment installed in the Facility. Such Licensed Professional Engineer shall be licensed in an appropriate engineering discipline for the required certification being made and be acceptable to PGE in its reasonable judgment.
- 1.15. "Lost Energy" means "Lost Energy" means ((the Guarantee of Mechanical Availability as set forth in 3.1.10 / MAP) X Net Output for a Calendar Year) Net Output for the Calendar Year. Lost Energy shall be zero unless the result of the calculation in this subsection results in a positive number.
- 1.16. "Lost Energy Value" means Lost Energy X the excess of the annual time-weighted average Mid-C Index Price for On Peak Hours and Off Peak Hours over the time weighted average Contract Price for On Peak and Off Peak Hours for the corresponding time period (provided that such excess shall not exceed the Contract Price and further provided that Lost Energy is deemed to be zero prior to reaching the Commercial Operation Date) plus any reasonable costs incurred by PGE to purchase replacement power and/or transmission to deliver the replacement power to the Point of Delivery (For Start-Up Lost Energy Value See 1.35).
- 1.17. "Mechanical Availability Percentage" or "MAP" shall mean that percentage for any Contract Year for the Facility calculated in accordance with the following formula:

MAP = 100 X (Operational Hours) /(Base Hours X Number of Units)

1.18. "Mid-C Index Price" means the Day Ahead Intercontinental Exchange ("ICE") index price for the bilateral OTC market for energy at the Mid-C Physical for Average On Peak Power and Average Off Peak Power found on the following website:

Blue Marmot/201 Talbott/177 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

https://www.theice.com/products/OTC/Physical-Energy/Electricity. In the event ICE no longer publishes this index, PGE and the Seller agree to select an alternative successor index representative of the Mid-C trading hub.

- 1.19. "Nameplate Capacity Rating" means the maximum capacity of the Facility as stated by the manufacturer, expressed in kW, which shall not exceed 10,000 kW.
- 1.20. "Net Dependable Capacity" means the maximum capacity the Facility can sustain over a specified period modified for seasonal limitations, if any, and reduced by the capacity required for station service or auxiliaries.
- 1.21. "Net Output" means all energy expressed in kWhs produced by the Facility, less station and other onsite use and less transformation and transmission losses.
- 1.22. "Number of Units" means the number of Generation Units in the Facility as specified in Exhibit A.
 - 1.23. "Off-Peak Hours" has the meaning provided in the Schedule.
 - 1.24. "On-Peak Hours" has the meaning provided in the Schedule.
- 1.25. "Operational Hours" for the Facility means the total across all Generation Units of the number of hours each of the Facility's Generation Units are potentially capable of producing power at its Nameplate Capacity Rating regardless of actual weather conditions, season and the time of day or night, without any mechanical operating constraint or restriction, and potentially capable of delivering such power to the Point of Delivery in a Contract Year. During up to, but not more than, two hundred (200) hours of Planned Maintenance during a Contract Year for each Generation Unit and hours during which an event of Force Majeure exists, a Generation Unit shall be considered potentially capable of delivering such power to the Point of Delivery. For example, in the absence of any Planned Maintenance beyond 200 hours on any Generation Unit or Event of Force Majeure, the Operational Hours for a wind farm with five (5) separate two (2) MW turbines would be 43,800 for a Contract Year.
- 1.26. "Planned Maintenance" means outages scheduled ninety (90) days in advance, with PGE's prior written consent, which shall not be unreasonably withheld.
 - 1.27. "Point of Delivery" means the PGE system.
- 1.28. "Pre-Commercial Operation Date Minimum Net Output" shall mean, unless such MWh is specifically set forth by Seller in Exhibit A, an amount in MWh equal to seventy-five percent (75%) of Nameplate Capacity Rating X thirty percent (30%) for a wind or other renewable QF or fifty percent (50%) for a solar QF X (whole months since the date selected in Section 2.2.1 / 12) X (8760 hours 200 hours (assumed Planned Maintenance)) for each month. If Seller has provided specific expected monthly Net Output amounts for the Facility in Exhibit A, "Pre-Commercial Operation Date Minimum Net Output" shall mean seventy-five percent (75%) X expected net output set forth in Exhibit A for each month.

Blue Marmot/201 Talbott/178 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

- 1.29. "Prime Rate" means the publicly announced prime rate or reference rate for commercial loans to large businesses with the highest credit rating in the United States in effect from time to time quoted by Citibank, N.A. If a Citibank, N.A. prime rate is not available, the applicable Prime Rate shall be the announced prime rate or reference rate for commercial loans in effect from time to time quoted by a bank with \$10 billion or more in assets in New York City, N.Y., selected by the Party to whom interest based on the prime rate is being paid.
- 1.30. "Prudent Electrical Practices" means those practices, methods, standards and acts engaged in or approved by a significant portion of the electric power industry in the Western Electricity Coordinating Council that at the relevant time period, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with good business practices, reliability, economy, safety and expedition, and which practices, methods, standards and acts reflect due regard for operation and maintenance standards recommended by applicable equipment suppliers and manufacturers, operational limits, and all applicable laws and regulations. Prudent Electrical Practices are not intended to be limited to the optimum practice, method, standard or act to the exclusion of all others, but rather to those practices, methods and acts generally acceptable or approved by a significant portion of the electric power generation industry in the relevant region, during the relevant period, as described in the immediate preceding sentence.
- 1.31. "Required Facility Documents" means all licenses, permits, authorizations, and agreements necessary for construction, operation, interconnection, and maintenance of the Facility including without limitation those set forth in Exhibit B.
- 1.32. "RPS Attributes" means all attributes related to the Net Output generated by the Facility that are required in order to provide PGE with "qualifying electricity," as that term is defined in Oregon's Renewable Portfolio Standard Act, Ore. Rev. Stat. 469A.010, in effect at the time of execution of this Agreement. RPS Attributes do not include Environmental Attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity and not needed to ensure that there are zero net emissions associated with the generation of electricity.
- 1.33. "Schedule" shall mean PGE Schedule 201 filed with the Oregon Public Utilities Commission ("Commission") in effect on the Effective Date of this Agreement and attached hereto as Exhibit D, the terms of which are hereby incorporated by reference.
- 1.34. "Senior Lien" means a prior lien which has precedence as to the property under the lien over another lien or encumbrance
- 1.35. "Start-Up Lost Energy Value" means for the period after the date specified in Section 2.2.2 but prior to achievement of the Commercial Operation Date: zero, unless the Net Output is less than the pro-rated Pre-Commercial Operation Date Minimum Net Output for the applicable delay period, and the time-weighted average of the delay period's Mid-C Index Price for On-Peak Hours and Off-Peak Hours is greater

Blue Marmot/201 Talbott/179 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

than the time-weighted average of the delay period's Contract Price for On-Peak Hours and Off-Peak Hours, in which case Startup Lost Energy Value equals: (pro-rated Pre-Commercial Operation Date Minimum Net Output for the applicable period - Net Output for the applicable period) X (the lower of: the time-weighted average of the Contract Price for On-Peak hours and Off-Peak Hours during the applicable period; or (the time-weighted average of the Mid-C Index Price for On-Peak Hours and Off-Peak Hours during the applicable period). The time-weighted average in this section will reflect the relative proportions of On-Peak Hours and Off-Peak Hours in each day.

- 1.36. "Start-Up Testing" means the completion of applicable required factory and start-up tests as set forth in Exhibit C.
- 1.37. "Step-in Rights" means the right of one party to assume an intervening position to satisfy all terms of an agreement in the event the other party fails to perform its obligations under the agreement.
- 1.38. "Term" shall mean the period beginning on the Effective Date and ending on the Termination Date.
- 1.39. "Test Period" shall mean a period of sixty (60) days or a commercially reasonable period determined by the Seller.
- 1.40. "Transmission Agreement" means an agreement executed by the Seller and the Transmission Provider(s) for Transmission Services.
- 1.41. "Transmission Curtailment" means a limitation on Seller's ability to deliver any portion of the scheduled energy to PGE due to the unavailability of transmission to the Point of Delivery (for any reason other than Force Majeure).
- 1.42. "Transmission Curtailment Replacement Energy Cost" means the greater of zero or the amount calculated as: ((Mid-C Index Price Contract Price) X curtailed energy) for periods of Transmission Curtailment.
- 1.43. "Transmission Provider(s)" means the signatory (other than the Seller) to the Transmission Agreement.
- 1.44. "Transmission Services" means any and all services (including but not limited to ancillary services and control area services) required for the firm transmission and delivery of Energy from the Facility to the Point of Delivery for a term not less than the Term of this Agreement.

References to Recitals, Sections, and Exhibits are to be the recitals, sections and exhibits of this Agreement.

SECTION 2: TERM; COMMERCIAL OPERATION DATE

2.1. This Agreement shall become effective upon execution by both Parties ("Effective Date").

Blue Marmot/201 Talbott/180 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

- 2.2. Time is of the essence of this Agreement, and Seller's ability to meet certain requirements prior to the Commercial Operation Date and to complete all requirements to establish the Commercial Operation Date is critically important. Therefore,
 - 2.2.1. By March 1, 2020 Seller shall begin initial deliveries of Net Output; and
- 2.2.2. By <u>March 31, 2020</u> Seller shall have completed all requirements under Section 1.5 and shall have established the Commercial Operation Date.
- 2.2.3. Unless the Parties agree in writing that a later Commercial Operation Date is reasonable and necessary, the Commercial Operation Date shall be no more than three (3) years from the Effective Date. PGE will not unreasonably withhold agreement to a Commercial Operation Date that is more than three (3) years from the Effective date if the Seller has demonstrated that a later Commercial Operation Date is reasonable and necessary.
- 2.3. This Agreement shall terminate on the date <u>18 years after the effective</u> <u>date</u>, or the date the Agreement is terminated in accordance with Section 8 or 11, whichever is earlier ("Termination Date").

SECTION 3: REPRESENTATIONS AND WARRANTIES

- 3.1. Seller and PGE represent, covenant, and warrant as follows:
- 3.1.1. Seller warrants it is a <u>Limited Liability Company</u> duly organized under the laws of <u>Delaware</u>.
- 3.1.2. Seller warrants that the execution and delivery of this Agreement does not contravene any provision of, or constitute a default under, any indenture, mortgage, or other material agreement binding on Seller or any valid order of any court, or any regulatory agency or other body having authority to which Seller is subject.
- 3.1.3. Seller warrants that the Facility is and shall for the Term of this Agreement continue to be a "Qualifying Facility" ("QF") as that term is defined in the version of 18 C.F.R. Part 292 in effect on the Effective Date. Seller has provided the appropriate QF certification, which may include a Federal Energy Regulatory Commission ("FERC") self-certification to PGE prior to PGE's execution of this Agreement. At any time during the Term of this Agreement, PGE may require Seller to provide PGE with evidence satisfactory to PGE in its reasonable discretion that the Facility continues to qualify as a QF under all applicable requirements.
- 3.1.4. Seller warrants that it has not within the past two (2) years been the debtor in any bankruptcy proceeding, and Seller is and will continue to be for the Term of this Agreement current on all of its financial obligations.
- 3.1.5. Seller warrants that during the Term of this Agreement, all of Seller's right, title and interest in and to the Facility shall be free and clear of all liens and encumbrances other than liens and encumbrances arising from third-party financing of the Facility other than workers', mechanics', suppliers' or similar liens, or tax liens, in each case arising in the ordinary course of business that are either not yet due and

Blue Marmot/201 Talbott/181 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

payable or that have been released by means of a performance bond acceptable to PGE posted within eight (8) calendar days of the commencement of any proceeding to foreclose the lien.

- 3.1.6. Seller warrants that it will design and operate the Facility consistent with Prudent Electrical Practices.
- 3.1.7. Seller warrants that the Facility has a Nameplate Capacity Rating not greater than 10,000 kW.
 - 3.1.8. Seller warrants that Net Dependable Capacity of the Facility is **10,000** kW.
- 3.1.9. Seller estimates that the average annual Net Output to be delivered by the Facility to PGE is <u>21,900,000</u> kilowatt-hours ("kWh"), which amount PGE will include in its resource planning.
- 3.1.10. Seller represents and warrants that the Facility shall achieve the following Mechanical Availability Percentages ("Guarantee of Mechanical Availability"):
- 3.1.10.1. Ninety percent (90%) beginning in the first Contract Year and extending through the Term for the Facility, if the Facility was operational and sold electricity to PGE or another buyer prior to the Effective Date of this Agreement; or
- 3.1.10.2. Ninety percent (90%) beginning in Contract Year three and extending throughout the remainder of the Term.
- 3.1.10.3. Annually, within 90 days of the end of each Contract Year, Seller shall send to PGE a detailed written report demonstrating and providing evidence of the actual MAP for the previous Contract Year.
- 3.1.10.4. Seller's failure to meet the Guarantee of Mechanical Availability in a Calendar Year shall result in damages payable to PGE by Seller equal to the Lost Energy Value. PGE shall bill Seller for such damages in accordance with Section 7.
- 3.1.11. Seller will deliver from the Facility to PGE at the Point of Delivery Net Output not to exceed a maximum of <u>33,750,000</u> kWh of Net Output during each Contract Year ("Maximum Net Output"). The cost of delivering energy from the Facility to PGE is the sole responsibility of the Seller.
- 3.1.12. By the Commercial Operation Date, Seller has entered into a Generation Interconnection Agreement for a term not less than the term of this Agreement.
- 3.1.13. PGE warrants that it has not within the past two (2) years been the debtor in any bankruptcy proceeding, and PGE is and will continue to be for the Term of this Agreement current on all of its financial obligations.
- 3.1.14. Seller warrants that the Facility satisfies the eligibility requirements specified in the Definition of a Small Cogeneration Facility or Small Power Production Facility Eligible to Receive the Standard Renewable Rates and Standard Renewable PPA in PGE's Schedule and Seller will not make any changes in its ownership, control or management during the term of this Agreement that would cause it to not be in compliance with the Definition of a Small Cogeneration Facility or Small Power

Blue Marmot/201 Talbott/182 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

Production Facility Eligible to Receive the Standard Renewable Rates and Standard Renewable PPA in PGE's Schedule. Seller will provide, upon request by PGE not more frequently than every 36 months, such documentation and information as may be reasonably required to establish Seller's continued compliance with such Definition. PGE agrees to take reasonable steps to maintain the confidentiality of any portion of the above described documentation and information that the Seller identifies as confidential except PGE will provide all such confidential information to the Commission upon the Commission's request.

3.1.15. Seller warrants that it will comply with all requirements necessary for all Transferred RECs (as defined in Section 4.5) associated with Net Output to be issued, monitored, accounted for, and transferred by and through the Western Renewable Energy Generation System consistent with the provisions of OAR 330-160-0005 through OAR 330-160-0050. PGE warrants that it will reasonably cooperate in Seller's efforts to meet such requirements, including, for example serving as the qualified reporting entity for the Facility if the Facility is located in PGE's balancing authority.

SECTION 4: DELIVERY OF POWER, PRICE AND ENVIRONMENTAL ATTRIBUTES

- 4.1. Commencing on the Effective Date and continuing through the Term of this Agreement, Seller shall sell to PGE the entire Net Output delivered from the Facility at the Point of Delivery.
 - 4.2. PGE shall pay Seller the Contract Price for all delivered Net Output.
- 4.3. Upon completion of construction of the Facility, Seller shall provide PGE an As-built Supplement to specify the actual Facility as built. Seller shall not increase the Nameplate Capacity Rating above that specified in Exhibit A or increase the ability of the Facility to deliver Net Output in quantities in excess of the Net Dependable Capacity, or the Maximum Net Output as described in Section 3.1.11 above, through any means including, but not limited to, replacement, modification, or addition of existing equipment, except with prior written notice to PGE. In the event Seller increases the Nameplate Capacity Rating of the Facility to no more than 10,000 kW pursuant to this section, PGE shall pay the Contract Price for the additional delivered Net Output. In the event Seller increases the Nameplate Capacity Rating to greater than 10,000 kW, then Seller shall be required to enter into a new power purchase agreement for all delivered Net Output proportionally related to the increase of Nameplate Capacity above 10,000 kW.
- 4.4. Seller shall provide preschedules for all deliveries of energy hereunder, including identification of receiving and generating control areas, by 9:00:00 PPT on the last business day prior to the scheduled date of delivery. All energy shall be scheduled according to the most current North America Energy Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) scheduling rules and practices. The Parties' respective representatives shall maintain hourly real-time schedule coordination; provided, however, that in the absence of such coordination, the hourly schedule established by the exchange of preschedules shall be considered final. Seller and PGE shall maintain records of hourly energy schedules for accounting and

Blue Marmot/201 Talbott/183 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

operating purposes. The final E-Tag shall be the controlling evidence of the Parties' schedule. All energy shall be prescheduled according to customary WECC scheduling practices. Seller shall make commercially reasonable efforts to schedule in any hour an amount equal to its expected Net Output for such hour. Seller shall maintain a minimum of two years records of Net Output and shall agree to allow PGE to have access to such records and to imbalance information kept by the Transmission Provider.

From the start of the Renewable Resource Deficiency Period through the remainder of the Term of this Agreement, Seller shall provide and PGE shall acquire the RPS Attributes for the Contract Years as specified in the Schedule and Seller shall retain ownership of all other Environmental Attributes (if any). During the Renewable Resource Sufficiency Period, Seller shall retain all Environmental Attributes in accordance with the Schedule. The Contract Price includes full payment for the Net Output and any RPS Attributes transferred to PGE under this Agreement. With respect to Environmental Attributes not transferred to PGE under this Agreement ("Seller-Retained Environmental Attributes") Seller may report under §1605(b) of the Energy Policy Act of 1992 or under any applicable program as belonging to Seller any of the Seller-Retained Environmental Attributes, and PGE shall not report under such program that such Seller-Retained Environmental Attributes belong to it. With respect to RPS Attributes transferred to PGE under this Agreement ("Transferred RECs"), PGE may report under §1605(b) of the Energy Policy Act of 1992 or under any applicable program as belonging to it any of the Transferred RECs, and Seller shall not report under such program that such Transferred RECs belong to it.

SECTION 5: OPERATION AND CONTROL

- 5.1. Seller shall operate and maintain the Facility in a safe manner in accordance with the Generation Interconnection Agreement, and Prudent Electrical Practices. PGE shall have no obligation to purchase Net Output from the Facility to the extent the interconnection of the Facility to PGE's electric system is disconnected, suspended or interrupted, in whole or in part, pursuant to the Generation Interconnection Agreement, or to the extent generation curtailment is required as a result of Seller's noncompliance with the Generation Interconnection Agreement. Seller is solely responsible for the operation and maintenance of the Facility. PGE shall not, by reason of its decision to inspect or not to inspect the Facility, or by any action or inaction taken with respect to any such inspection, assume or be held responsible for any liability or occurrence arising from the operation and maintenance by Seller of the Facility.
- 5.2. Seller agrees to provide sixty (60) days advance written notice of any scheduled maintenance that would require shut down of the Facility for any period of time.
- 5.3. If the Facility ceases operation for unscheduled maintenance, Seller immediately shall notify PGE of the necessity of such unscheduled maintenance, the time when such maintenance has occurred or will occur, and the anticipated duration of such maintenance. Seller shall take all reasonable measures and exercise its best

Blue Marmot/201 Talbott/184 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

efforts to avoid unscheduled maintenance, to limit the duration of such unscheduled maintenance, and to perform unscheduled maintenance during Off-Peak hours.

SECTION 6: CREDITWORTHINESS

In the event Seller: a) is unable to represent or warrant as required by Section 3 that it has not been a debtor in any bankruptcy proceeding within the past two (2) years; b) becomes such a debtor during the Term; or c) is not or will not be current on all its financial obligations, Seller shall immediately notify PGE and shall promptly (and in no less than 10 days after notifying PGE) provide default security in an amount reasonably acceptable to PGE in one of the following forms: Senior Lien, Step-in Rights, a Cash Escrow or Letter of Credit. The amount of such default security that shall be acceptable to PGE shall be equal to: (annual On Peak Hours) X (On Peak Price – Off Peak Price) X (Net Dependable Capacity). Notwithstanding the foregoing, in the event Seller is not current on construction related financial obligations, Seller shall notify PGE of such delinquency and PGE may, in its discretion, grant an exception to the requirements to provide default security if the QF has negotiated financial arrangements with the construction loan lender that mitigate Seller's financial risk to PGE.

SECTION 7: BILLINGS, COMPUTATIONS AND PAYMENTS

- 7.1. On or before the thirtieth (30th) day following the end of each Billing Period, PGE shall send to Seller payment for Seller's deliveries of Net Output to PGE, together with computations supporting such payment. PGE may offset any such payment to reflect amounts owing from Seller to PGE pursuant to this Agreement and any other agreement related to the Facility between the Parties or otherwise. On or before the thirtieth (30th) day following the end of each Contract Year, PGE shall bill for any Lost Energy Value accrued pursuant to this Agreement.
- 7.2. Any amounts owing after the due date thereof shall bear interest at the Prime Rate plus two percent (2%) from the date due until paid; provided, however, that the interest rate shall at no time exceed the maximum rate allowed by applicable law.

SECTION 8: DEFAULT, REMEDIES AND TERMINATION

- 8.1. In addition to any other event that may constitute a default under this Agreement, the following events shall constitute defaults under this Agreement:
- 8.1.1. Breach by Seller or PGE of a representation or warranty, except for Section 3.1.4, set forth in this Agreement.
- 8.1.2. Seller's failure to provide default security, if required by Section 6, prior to delivery of any Net Output to PGE or within 10 days of notice.
- 8.1.3. Seller's failure to meet the Guarantee of Mechanical Availability established in Section 3.1.10 for two consecutive Contract Years or Seller's failure to provide any written report required by that section.
 - 8.1.4. If Seller is no longer a Qualifying Facility.
 - 8.1.5. Failure of PGE to make any required payment pursuant to Section 7.1.

Blue Marmot/201 Talbott/185 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

- 8.1.6. Seller's failure to meet the Commercial Operation Date.
- 8.2. In the event of a default under Section 8.1.6, PGE may provide Seller with written notice of default. Seller shall have one year in which to cure the default during which time the Seller shall pay PGE damages equal to the Lost Energy Value. If Seller is unable to cure the default, PGE may immediately terminate this Agreement as provided in Section 8.3. PGE's resource sufficiency/deficiency position shall have no bearing on PGE's right to terminate the Agreement under this Section 8.2.
- 8.3. In the event of a default hereunder, except as otherwise provided in this Agreement, the non-defaulting party may immediately terminate this Agreement at its sole discretion by delivering written notice to the other Party. In addition, the non-defaulting Party may pursue any and all legal or equitable remedies provided by law or pursuant to this Agreement including damages related to the need to procure replacement power. A termination hereunder shall be effective upon the date of delivery of notice, as provided in Section 20. The rights provided in this Section 8 are cumulative such that the exercise of one or more rights shall not constitute a waiver of any other rights.
- 8.4. If this Agreement is terminated as provided in this Section 8, PGE shall make all payments, within thirty (30) days, that, pursuant to the terms of this Agreement, are owed to Seller as of the time of receipt of notice of default. PGE shall not be required to pay Seller for any Net Output delivered by Seller after such notice of default.
- 8.5. In the event PGE terminates this Agreement pursuant to this Section 8, and Seller wishes to again sell Net Output to PGE following such termination, PGE in its sole discretion may require that Seller shall do so subject to the terms of this Agreement, including but not limited to the Contract Price until the Term of this Agreement (as set forth in Section 2.3) would have run in due course had the Agreement remained in effect. At such time Seller and PGE agree to execute a written document ratifying the terms of this Agreement.
- 8.6. Sections 8.1, 8.4, 8.5, 10, and 19.2 shall survive termination of this Agreement.

SECTION 9: TRANSMISSION CURTAILMENTS

- 9.1. Seller shall give PGE notice as soon as reasonably practicable of any Transmission Curtailment that is likely to affect Seller's ability to deliver any portion of energy scheduled pursuant to Section 4.4 of this Agreement.
- 9.2. If as the result of a Transmission Curtailment, Seller does not deliver any portion of energy (including real-time adjustments), scheduled pursuant to Section 4.4 of this Agreement, Seller shall pay PGE the Transmission Curtailment Replacement Energy Cost for the number of MWh of energy reasonably determined by PGE as the difference between (i) the scheduled energy that would have been delivered to PGE under this Agreement during the period of Transmission Curtailment and (ii) the actual energy, if any, that was delivered to PGE for the period.

Blue Marmot/201 Talbott/186 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

SECTION 10: INDEMNIFICATION AND LIABILITY

- 10.1. Seller agrees to defend, indemnify and hold harmless PGE, its directors, officers, agents, and representatives against and from any and all loss, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with Seller's delivery of electric power to PGE or with the facilities at or prior to the Point of Delivery, or otherwise arising out of this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PGE, Seller or others, excepting to the extent such loss, claim, action or suit may be caused by the negligence of PGE, its directors, officers, employees, agents or representatives.
- 10.2. PGE agrees to defend, indemnify and hold harmless Seller, its directors, officers, agents, and representatives against and from any and all loss, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with PGE's receipt of electric power from Seller or with the facilities at or after the Point of Delivery, or otherwise arising out of this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PGE, Seller or others, excepting to the extent such loss, claim, action or suit may be caused by the negligence of Seller, its directors, officers, employees, agents or representatives.
- 10.3. Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a Party to this Agreement. No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or to the public, nor affect the status of PGE as an independent public utility corporation or Seller as an independent individual or entity.
- 10.4. NEITHER PARTY SHALL BE LIABLE TO THE OTHER FOR SPECIAL, PUNITIVE, INDIRECT OR CONSEQUENTIAL DAMAGES, WHETHER ARISING FROM CONTRACT, TORT (INCLUDING NEGLIGENCE), STRICT LIABILITY OR OTHERWISE.

SECTION 11: INSURANCE

11.1. Prior to the connection of the Facility to PGE's electric system, provided such Facility has a design capacity of 200 kW or more, Seller shall secure and continuously carry for the Term hereof, with an insurance company or companies rated not lower than "B+" by the A. M. Best Company, insurance policies for bodily injury and property damage liability. Such insurance shall include provisions or endorsements naming PGE, it directors, officers and employees as additional insureds; provisions that such insurance is primary insurance with respect to the interest of PGE and that any insurance or self-insurance maintained by PGE is excess and not contributory insurance with the insurance required hereunder; a cross-liability or severability of

Blue Marmot/201 Talbott/187 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

insurance interest clause; and provisions that such policies shall not be canceled or their limits of liability reduced without thirty (30) days' prior written notice to PGE. Initial limits of liability for all requirements under this section shall be \$1,000,000 million single limit, which limits may be required to be increased or decreased by PGE as PGE determines in its reasonable judgment economic conditions or claims experience may warrant.

- 11.2. Prior to the connection of the Facility to PGE's electric system, provided such facility has a design capacity of 200 kW or more, Seller shall secure and continuously carry for the Term hereof, in an insurance company or companies rated not lower than "B+" by the A. M. Best Company, insurance acceptable to PGE against property damage or destruction in an amount not less than the cost of replacement of the Facility. Seller promptly shall notify PGE of any loss or damage to the Facility. Unless the Parties agree otherwise, Seller shall repair or replace the damaged or destroyed Facility, or if the facility is destroyed or substantially destroyed, it may terminate this Agreement. Such termination shall be effective upon receipt by PGE of written notice from Seller. Seller shall waive its insurers' rights of subrogation against PGE regarding Facility property losses.
- 11.3. Prior to the connection of the Facility to PGE's electric system and at all other times such insurance policies are renewed or changed, Seller shall provide PGE with a copy of each insurance policy required under this Section, certified as a true copy by an authorized representative of the issuing insurance company or, at the discretion of PGE, in lieu thereof, a certificate in a form satisfactory to PGE certifying the issuance of such insurance. If Seller fails to provide PGE with copies of such currently effective insurance policies or certificates of insurance, PGE at its sole discretion and without limitation of other remedies, may upon ten (10) days advance written notice by certified or registered mail to Seller either withhold payments due Seller until PGE has received such documents, or purchase the satisfactory insurance and offset the cost of obtaining such insurance from subsequent power purchase payments under this Agreement.

SECTION 12: FORCE MAJEURE

12.1. As used in this Agreement, "Force Majeure" or "an event of Force Majeure" means any cause beyond the reasonable control of the Seller or of PGE which, despite the exercise of due diligence, such Party is unable to prevent or overcome. By way of example, Force Majeure may include but is not limited to acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes, and other labor disturbances, earthquakes, fires, lightning, epidemics, sabotage, restraint by court order or other delay or failure in the performance as a result of any action or inaction on behalf of a public authority which by the exercise of reasonable foresight such Party could not reasonably have been expected to avoid and by the exercise of due diligence, it shall be unable to overcome, subject, in each case, to the requirements of the first sentence of this paragraph. Force Majeure, however, specifically excludes the cost or availability of resources to operate the Facility, changes in market conditions that affect

Blue Marmot/201 Talbott/188 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

the price of energy or transmission, wind or water droughts, and obligations for the payment of money when due.

- 12.2. If either Party is rendered wholly or in part unable to perform its obligation under this Agreement because of an event of Force Majeure, that Party shall be excused from whatever performance is affected by the event of Force Majeure to the extent and for the duration of the Force Majeure, after which such Party shall recommence performance of such obligation, provided that:
- 12.2.1. the non-performing Party, shall, promptly, but in any case within one (1) week after the occurrence of the Force Majeure, give the other Party written notice describing the particulars of the occurrence; and
- 12.2.2. the suspension of performance shall be of no greater scope and of no longer duration than is required by the Force Majeure; and
- 12.2.3. the non-performing Party uses its best efforts to remedy its inability to perform its obligations under this Agreement.
- 12.3. No obligations of either Party which arose before the Force Majeure causing the suspension of performance shall be excused as a result of the Force Majeure.
- 12.4. Neither Party shall be required to settle any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to the Party's best interests.

SECTION 13: SEVERAL OBLIGATIONS

Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership or joint venture or to impose a trust or partnership duty, obligation or liability between the Parties. If Seller includes two or more parties, each such party shall be jointly and severally liable for Seller's obligations under this Agreement.

SECTION 14: CHOICE OF LAW

This Agreement shall be interpreted and enforced in accordance with the laws of the state of Oregon, excluding any choice of law rules which may direct the application of the laws of another jurisdiction.

SECTION 15: PARTIAL INVALIDITY AND PURPA REPEAL

It is not the intention of the Parties to violate any laws governing the subject matter of this Agreement. If any of the terms of the Agreement are finally held or determined to be invalid, illegal or void as being contrary to any applicable law or public policy, all other terms of the Agreement shall remain in effect. If any terms are finally held or determined to be invalid, illegal or void, the Parties shall enter into negotiations concerning the terms affected by such decision for the purpose of achieving conformity with requirements of any applicable law and the intent of the Parties to this Agreement.

Blue Marmot/201 Talbott/189 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

In the event the Public Utility Regulatory Policies Act (PURPA) is repealed, this Agreement shall not terminate prior to the Termination Date, unless such termination is mandated by state or federal law.

SECTION 16: WAIVER

Any waiver at any time by either Party of its rights with respect to a default under this Agreement or with respect to any other matters arising in connection with this Agreement must be in writing, and such waiver shall not be deemed a waiver with respect to any subsequent default or other matter.

SECTION 17: GOVERNMENTAL JURISDICTION AND AUTHORIZATIONS

This Agreement is subject to the jurisdiction of those governmental agencies having control over either Party or this Agreement. Seller shall at all times maintain in effect all local, state and federal licenses, permits and other approvals as then may be required by law for the construction, operation and maintenance of the Facility, and shall provide upon request copies of the same to PGE.

SECTION 18: SUCCESSORS AND ASSIGNS

This Agreement and all of the terms hereof shall be binding upon and inure to the benefit of the respective successors and assigns of the Parties. No assignment hereof by either Party shall become effective without the written consent of the other Party being first obtained and such consent shall not be unreasonably withheld. Notwithstanding the foregoing, either Party may assign this Agreement without the other Party's consent as part of (a) a sale of all or substantially all of the assigning Party's assets, or (b) a merger, consolidation or other reorganization of the assigning Party.

SECTION 19: ENTIRE AGREEMENT

- 19.1. This Agreement supersedes all prior agreements, proposals, representations, negotiations, discussions or letters, whether oral or in writing, regarding PGE's purchase of Net Output from the Facility. No modification of this Agreement shall be effective unless it is in writing and signed by both Parties.
- 19.2. By executing this Agreement, Seller releases PGE from any third party claims related to the Facility, known or unknown, which may have arisen prior to the Effective Date.

SECTION 20: NOTICES

20.1. All notices except as otherwise provided in this Agreement shall be in writing, shall be directed as follows and shall be considered delivered if delivered in person or when deposited in the U.S. Mail, postage prepaid by certified or registered mail and return receipt requested:

Blue Marmot/201 Talbott/190 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

	To Seller:	Blue Marmot VII LLCc/o EDP Renewables North America LLC;Attention: General Counsel;808 Travis Suite 808Houston, TX 77002	
	with a copy to:		
	To PGE:	Contracts Manager QF Contracts, 3WTC0306 PGE - 121 SW Salmon St. Portland, Oregon 97204	
20.	ir addresses, by pro	may change the person to whom such notices are addressed viding written notices thereof in accordance with this Section REOF, the Parties hereto have caused this Agreement to be a names as of the Effective Date.	n
PGE			
Name Title: ₋	:		
	Marmot VII LLC e Seller)		
Name Title: ₋	:		

Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

EXHIBIT A DESCRIPTION OF SELLER'S FACILITY

The facility will be a solar PV plant consisting of 38,715 polycrystalline modules of nominal 335W rating each. Total plant rating will be 12.970 MWdc/10MWac. Modules will be mounted to single-axis trackers.

Central inverter stations will be located at intermediate points in the PV field.

Modules will be evenly distributed to the inverter stations. The total inverter nameplate rating will be 10.0MWac. Each inverter will be directly coupled to a 34.5kV step-up transformer. The transformers will be connected to a 34.5kV AC collection system, which will feed into the plant switchgear.

The plant switchgear will feed a 34.5kV transmission line, which will run overhead approximately 6.5 miles to the PacifiCorp Mile-Hi Substation.

Inside the Mile-Hi Substation, the transmission line will connect to a new bay containing a facility-owned 34.5kV/115kV GSU transformer, associated breakers, switching, bus, and controls.

The facility-owned components at Mile-Hi substation are considered part of the self-certified qualifying facility.

iolar Facility Characteristics:	Note this information is considered representative design information which is to be updated at the time of projec construction and is subject to design finalization
Generation	
a. PVSyst (or equivalent) simulation results detail, including but not limited to:	
i. Annual MWh (AC) for the first calendar year of commercial operation.	23,875
ii. Annual degradation factor	0,709
iii. Average 24-hr profile of generation MWh (AC) for each month during the first calendar year	See tab "Generation
	279
iv. Expected Solar Capacity Factor	4.7
v. Maximum annual output (monthly MWh detail)	See tab "Generation
iv, Loss Diagram	See tab "Generation
Description of Modules:	
a. Module type	Polycrystalline Silicon
b. #of modules	38,715
c. Max power voltage	37.4V
d. Max power current	8.97A
e. Max system voltage	1500V
f. Total DC system size	12970kW
	1297UKW
Description of Racking	
a. Racking	
i. Type: (fixed tilt, single-axis tracking, or dual-axis tracking, etc.)	Single-Axis Tracking
ii. Tilt angle (if fixed-tilt)	N/A
iii. Azimuth (default = south-facing)	South-Facing
Description of Inverters:	
a. Number of Inverters	5
b. Model	ABB PVS980-58-1818kVA-6
c. Maximum Power (kW)	2910kW DC
d. Operating Voltage (VAC)	600
e. Max. Output Current (A)	1925A
f. Rated DC Voltage	1500
g. Rated DC current	1945
h. Maximum Output (kW)	2000
g. Facility AC Capacity Rating	10.0MW
	1.297
h. Inverter loading ratio	
i. Facility AC rating	10.0MW
. Description of transformers	
Inverter LV-MV	
a. # of transformers	5.
b. Model	ABB PadPlus+
c. High Voltage Rating	34.500
d. Low Voltage Rating	600
e. MVA rating	2.0 each, 10.0 total
f. High voltage connection	Wye-Ground
g. Low voltage connection	Wye
GSU MV-HV	
a. # of transformers	1
b. Model	ABB 10MVA
c. High Voltage Rating	115.000
d. Low Voltage Rating	34,500
e. MVA rating	10/12.5 ONAF
f. High voltage connection	Wye
g. Low voltage connection	Delta
	Meter shall be revenue-grade, located at POI. POI shall be slack bu
	on the high-side bushing of plant GSU transformer at Mile Hi
	Substation. Revenue meter shall transmit real-time data pulses
	(instantaneous MW, MVAR, KWH) to Operator's billing data
	program. Customer's 35kV switchgear at Mile Hi shall be fitted wit
	Customer meter as an alternate data source. Breakers and relays
Description of metering, communications, and monitoring	at Customer's PV plant shall connect to operator SCADA system at
and the same of th	Mile Hi substation via OPGW run on proposed Customer
	transmission line. Customer shall install line-protection panel,
	metering equipment and accessories, communication battery
	system, fiber optic network device and SCADA RTU (Remote
	Terminal Unit) in existing Mile HI relay/control building to control,
	monitor, and transmit data to Operator and back to PV plant SCADA.

Blue Marmot/201 Talbott/193 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

	7. Description of station service requirements	15KVA, 240/120V 1-phase service at PV plant substation for Relay/SCADA/O&M building and plant accessory loads. 5KVA, 240/120V 1-phase at Mile Hi substation for Customer controls equipment.
		Transmission line shall be new radial line consisting of 34.5KV ACSR, 1-conductor per phase with OPGW on wood poles, approx. 6.5 miles. Line will originate at PV plant 34.5kV main switchgear and terminate at dead-end structure feeding a new 35kV breaker at Mile Hi Substation. 35kV breaker will feed new GSU and new 115kV breaker at Mile Hi Substation. POI shall be slack bus between new 115kV breaker and existing 115kV bus at Mile Hi Substation. Seller is taking necessary steps to execute required interconnection
		and transmission agreements prior to commercial operation date.
į	9. Transaction Service Request Number, Interconnection Queue number, and System impact/interconnection study document	Seller is taking necessary steps to execute required interconnection and transmission agreements prior to commercial operation date.

EXHIBIT B REQUIRED FACILITY DOCUMENTS

Sellers Generation Interconnection Agreement

Transmission Service Agreement with PacifiCorp

Lease agreement

Conditional Use Permit issued by Lake County

Any additional permits that might be required by Lake County or Oregon Department of Environmental Quality, including access permit, building and electric permits, and storm water prevention permit

FERC Qualifying Facility self-certification

EXHIBIT C START-UP TESTING

VISUAL AND MECHANICAL INSPECTIONS

INVERTER COMMISSIONING

ELECTRICAL OPERATION TESTS

SYSTEM MONITORING VERIFICATION

TRACKER VERIFICATION

INFRARED SCANS

BLOCK TESTING

72-HOUR FUNCTIONAL TEST

GRID MATCH TEST

POWER CHARACTERIZATION

REVENUE METER VERIFICATION

REACTIVE POWER TEST

POWER OUTPUT TEST - PLANT PERFORMANCE AND ACCEPTANCE

EXHIBIT D SCHEDULE

SCHEDULE 201 QUALIFYING FACILITY 10 MW or LESS AVOIDED COST POWER PURCHASE INFORMATION

PURPOSE

To provide information about Standard Avoided Costs and Renewable Avoided Costs, Standard Power Purchase Agreements (PPA) and Negotiated PPAs, power purchase prices and price options for power delivered by a Qualifying Facility (QF) to the Company with nameplate capacity of 10,000 kW (10MW) or less.

AVAILABLE

To owners of QFs making sales of electricity to the Company in the State of Oregon (Seller).

APPLICABLE

For power purchased from small power production or cogeneration facilities that are QFs as defined in 18 Code of Federal Regulations (CFR) Section 292, that meet the eligibility requirements described herein and where the energy is delivered to the Company's system and made available for Company purchase pursuant to a Standard PPA.

ESTABLISHING CREDITWORTHINESS

The Seller must establish creditworthiness prior to service under this schedule. For a Standard PPA, a Seller may establish creditworthiness with a written acknowledgment that it is current on all existing debt obligations and that it was not a debtor in a bankruptcy proceeding within the preceding 24 months. If the Seller is not able to establish creditworthiness, the Seller must provide security deemed sufficient by the Company as set forth in the Standard PPA.

POWER PURCHASE INFORMATION

A Seller may call the Power Production Coordinator at (503) 464-8000 to obtain more information about being a Seller or how to apply for service under this schedule.

PPA

In accordance with terms set forth in this schedule and the Commission's Rules as applicable, the Company will purchase any Energy in excess of station service (power necessary to produce generation) and amounts attributable to conversion losses, which are made available from the Seller.

A Seller must execute a PPA with the Company prior to delivery of power to the Company. The agreement will have a term of up to 20 years as selected by the QF.

A QF with a nameplate capacity rating of 10 MW or less as defined herein may elect the option of a Standard PPA.

PPA (Continued)

Any Seller may elect to negotiate a PPA with the Company. Such negotiation will comply with the requirements of the Federal Energy Regulatory Commission (FERC), and the Commission including the guidelines in Order No. 07-360, and Schedule 202. Negotiations for power purchase pricing will be based on either the filed Standard Avoided Costs or Renewable Avoided Costs in effect at that time.

STANDARD PPA (Nameplate capacity of 10 MW or less)

A Seller choosing a Standard PPA will complete all informational and price option selection requirements in the applicable Standard PPA and submit the executed Agreement to the Company prior to service under this schedule. The Standard PPA is available at www.portlandgeneral.com. The available Standard PPAs are:

- Standard In-System Non-Variable Power Purchase Agreement
- Standard Off-System Non-Variable Power Purchase Agreement
- Standard In-System Variable Power Purchase Agreement
- Standard Off-System Variable Power Purchase Agreement
- Standard Renewable In-System Non-Variable Power Purchase Agreement
- Standard Renewable Off-System Non-Variable Power Purchase Agreement
- Standard Renewable In-System Variable Power Purchase Agreement
- Standard Renewable Off-System Variable Power Purchase Agreement

The Standard PPAs applicable to variable resources are available only to QFs utilizing wind, solar or run of river hydro as the primary motive force.

GUIDELINES FOR 10 MW OR LESS FACILITIES ELECTING STANDARD PPA

To execute the Standard PPA the Seller must complete all of the general project information requested in the applicable Standard PPA.

When all information required in the Standard PPA has been received in writing from the Seller, the Company will respond within 15 business days with a draft Standard PPA.

The Seller may request in writing that the Company prepare a final draft Standard PPA. The Company will respond to this request within 15 business days. In connection with such request, the QF must provide the Company with any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft Standard PPA.

When both parties are in full agreement as to all terms and conditions of the draft Standard PPA, the Company will prepare and forward to the Seller a final executable version of the agreement within 15 business days. Following the Company's execution, an executed copy will be returned to the Seller. Prices and other terms and conditions in the PPA will not be final and binding until the Standard PPA has been executed by both parties.

OFF-SYSTEM PPA

A Seller with a facility that interconnects with an electric system other than the Company's electric system may enter into a PPA with the Company after following the applicable Standard or Negotiated PPA guidelines and making the arrangements necessary for transmission of power to the Company's system.

BASIS FOR POWER PURCHASE PRICE

AVOIDED COST SUMMARY

The power purchase prices are based on either the Company's Standard Avoided Costs or Renewable Avoided Costs in effect at the time the agreement is executed. Avoided Costs are defined in 18 CFR 292.101(6) as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."

Monthly On-Peak prices are included in both the Standard Avoided Costs as listed in Tables 1a, 2a, and 3a and Renewable Avoided Costs as listed in Tables 4a, 5a, and 6a. Monthly Off-Peak prices are included in both the Standard Avoided Costs as listed in Tables 1b, 2b, and 3b and Renewable Avoided Costs as listed in Tables 4b, 5b, and 6b.

ON-PEAK PERIOD

The On-Peak period is 6:00 a.m. until 10:00 p.m., Monday through Saturday.

OFF-PEAK PERIOD

The Off-Peak period is 10:00 p.m. until 6:00 a.m., Monday through Saturday, and all day on Sunday.

Standard Avoided Costs are based on forward market price estimates through the Resource Sufficiency Period, the period of time during which the Company's Standard Avoided Costs are associated with incremental purchases of Energy and capacity from the market. For the Resource Deficiency Period, the Standard Avoided Costs reflect the fully allocated costs of a natural gas fueled combined cycle combustion turbine (CCCT) including fuel and capital costs. The CCCT Avoided Costs are based on the variable cost of Energy plus capitalized Energy costs at a 93% capacity factor based on a natural gas price forecast, with prices modified for shrinkage and transportation costs.

Renewable Avoided Costs are based on forward market price estimates through the Renewable Resource Sufficiency Period, the period of time during which the Company's Renewable Avoided Costs are associated with incremental purchases of energy and capacity from the market. For the Renewable Resource Deficiency Period, the Renewable Avoided Costs reflect the fully allocated costs of a wind plant including capital costs.

PRICING FOR STANDARD PPA

Pricing represents the purchase price per MWh the Company will pay for electricity delivered to a Point of Delivery (POD) within the Company's service territory pursuant to a Standard PPA up to the nameplate rating of the QF in any hour. Any Energy delivered in excess of the nameplate rating will be purchased at the applicable Off-Peak Prices for the selected pricing option.

The Standard PPA pricing will be based on either the Standard or Renewable Avoided Costs in effect at the time the agreement is executed.

The Company will pay the Seller either the Off-Peak Standard Avoided Cost pursuant to Tables 1b, 2b, or 3b or the Off-Peak Renewable Avoided Costs pursuant to Tables 4b, 5b, or 6b for: (a) all Net Output delivered prior to the Commercial Operation Date; (b) all Net Output deliveries greater than Maximum Net Output in any PPA year; (c) any generation subject to and as adjusted by the provisions of Section 4.3 of the Standard PPA; (d) Net Output delivered in the Off-Peak Period; and (e) deliveries above the nameplate capacity in any hour. The Company will pay the Seller either the On-Peak Standard Avoided Cost pursuant to Tables 1a, 2a, or 3a or the On-Peak Renewable Avoided Costs pursuant to Tables 4a, 5a, or 6a for all other Net Output. (See the PPA for defined terms.)

1) Standard Fixed Price Option

The Standard Fixed Price Option is based on Standard Avoided Costs including forecasted natural gas prices. It is available to all QFs.

This option is available for a maximum term of 15 years. Prices will be as established at the time the Standard PPA is executed and will be equal to the Standard Avoided Costs in Tables 1a and 1b, 2a and 2b, or 3a and 3c, depending on the type of QF, effective at execution. QFs using any resource type other than wind and solar are assumed to be Base Load QFs.

Prices paid to the Seller under the Standard Fixed Price Option include adjustments for the capacity contribution of the QF resource type relative to that of the avoided proxy resource. Both the Base Load QF resources (Tables 1a and 1b) and the avoided proxy resource, the basis used to determine Standard Avoided Costs for the Standard Fixed Price Option, are assumed to have a capacity contribution to peak of 100%. The capacity contribution for Wind QF resources (Tables 2a and 2b) is assumed to be 5%. The capacity contribution for Solar QF resources (Tables 3a and 3b) is assumed to be 5%.

Prices paid to the Seller under the Standard Fixed Price Option for Wind QFs (Tables 2a and 2b) include a reduction for the wind integration costs in Table 7. However, if the Wind QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the wind integration charges in Table 7, in addition to the prices listed in Tables 2a and 2b, for a net-zero effect.

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

Sellers with PPAs exceeding 15 years will receive pricing equal to the Mid-C Index Price for all years up to five in excess of the initial 15.

	TABLE 1a												
						ided Cos	ts						
			St	andard F	ixed Pric	e Option	for Base	Load QF	•				
				0	n-Peak F	orecast (\$/MWH)						
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2016	28.21	22.46	15.61	14.71	12.46	16.96	23.96	26.96	24.96	23.71	26.71	31.46	
2017	29.96	28.21	24.71	20.96	19.46	20.46	27.96	30.96	29.46	27.71	28.71	33.71	
2018	31.71	31.11	28.11	22.13	21.28	21.28	29.93	33.37	30.63	28.61	31.86	35.71	
2019	33.94	31.95	27.97	23.70	22.00	23.13	31.67	35.08	33.37	31.38	32.52	38.21	
2020	35.74	33.64	29.45	24.95	23.15	24.35	33.34	36.94	35.14	33.04	34.24	40.24	
2021	67.43	67.34	65.41	64.69	64.41	64.50	64.61	64.73	64.84	65.48	68.60	68.72	
2022	69.01	68.84	68.08	67.13	66.81	66.91	67.04	67.17	67.29	67.83	71.38	71.70	
2023	71.95	71.76	70.39	69.19	69.07	69.18	69.31	69.45	69.58	70.12	73.56	73.70	
2024	74.17	73.85	72.67	71.29	71.10	71.21	71.35	71.50	71.63	72.20	76.49	76.64	
2025	77.19	77.30	75.84	74.88	75.02	75.14	75.30	75.47	75.62	75.80	82.57	82.89	
2026	85.18	85.30	82.77	81.28	81.22	81.36	81.56	81.74	81.90	82.36	89.02	88.72	
2027	86.85	86.76	85.14	83.12	82.89	83.03	83.00	83.32	83.46	83.97	91.39	91.15	
2028	89.32	89.31	87.96	85.46	85.30	85.46	85.31	85.64	85.95	86.65	94.66	93.55	
2029	94.06	93.99	91.23	88.74	87.97	88.15	87.71	88.06	88.61	89.34	98.37	98.11	
2030	97.60	97.54	94.87	92.62	92.40	92.57	92.61	93.00	93.12	93.68	102.42	102.70	
2031	99.56	99.50	96.78	94.48	94.26	94.43	94.47	94.87	94.99	95.56	104.47	104.76	
2032	103.85	103.80	100.57	98.18	97.96	98.15	98.23	98.65	98.76	99.36	108.86	109.41	
2033	106.56	106.51	103.17	100.72	100.50	100.69	100.78	101.21	101.32	101.93	111.67	112.26	
2034	109.12	109.07	105.60	103.10	102.88	103.08	103.17	103.61	103.72	104.35	114.33	114.96	
2035	111.55	111.51	107.91	105.35	105.12	105.33	105.43	105.89	105.99	106.63	116.87	117.54	
2036	113.85	113.80	110.14	107.53	107.30	107.51	107.60	108.07	108.18	108.83	119.27	119.95	
2037	116.50	116.45	112.72	110.06	109.82	110.04	110.14	110.61	110.73	111.39	122.03	122.73	
2038	119.08	119.03	115.22	112.51	112.27	112.49	112.59	113.08	113.19	113.87	124.71	125.42	
2039	121.47	121.42	117.54	114.77	114.53	114.75	114.85	115.35	115.47	116.15	127.21	127.93	
2040	124.25	124.20	120.25	117.43	117.18	117.41	117.51	118.02	118.14	118.84	130.10	130.85	
2041	126.72	126.67	122.64	119.76	119.51	119.74	119.85	120.36	120.49	121.20	132.68	133.44	

					TA	ABLE 1b						
					Avoi	ided Cos	ts					
			Sta	andard F	ixed Price	e Option	for Base	Load QF				
				0	ff-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	25.61	20.71	13.96	11.41	6.31	10.11	15.71	20.96	20.96	21.21	23.46	26.71
2017	25.71	24.21	22.21	15.71	13.71	12.71	19.71	25.21	25.46	24.71	25.71	27.96
2018	26.17	28.12	25.56	19.46	14.68	12.54	19.71	27.04	26.93	25.35	28.20	30.62
2019	29.84	28.09	25.75	18.15	15.81	14.64	22.83	29.26	29.55	28.67	29.84	32.47
2020	31.75	29.88	27.38	19.28	16.79	15.54	24.27	31.12	31.43	30.50	31.75	34.55
2021	28.88	28.79	26.86	26.15	25.87	25.95	26.07	26.19	26.30	26.94	30.06	30.18
2022	29.73	29.56	28.79	27.85	27.53	27.63	27.75	27.88	28.00	28.54	32.09	32.42
2023	31.78	31.59	30.21	29.01	28.90	29.00	29.14	29.27	29.40	29.95	33.38	33.52
2024	33.48	33.16	31.98	30.60	30.41	30.52	30.66	30.81	30.95	31.51	35.80	35.96
2025	35.58	35.69	34.24	33.27	33.42	33.53	33.70	33.86	34.01	34.19	40.97	41.28
2026	42.77	42.89	40.36	38.87	38.81	38.95	39.15	39.34	39.50	39.95	46.62	46.31
2027	43.63	43.54	41.91	39.89	39.66	39.80	39.77	40.09	40.24	40.74	48.16	47.92
2028	45.26	45.25	43.90	41.40	41.23	41.40	41.25	41.58	41.89	42.59	50.60	49.48
2029	49.15	49.08	46.32	43.83	43.06	43.24	42.80	43.15	43.70	44.43	53.46	53.20
2030	51.82	51.76	49.09	46.84	46.62	46.79	46.83	47.22	47.34	47.90	56.64	56.92
2031	52.90	52.84	50.11	47.82	47.59	47.77	47.81	48.21	48.33	48.90	57.81	58.10
2032	56.59	56.54	53.31	50.92	50.70	50.89	50.97	51.39	51.50	52.10	61.60	62.15
2033	58.08	58.03	54.69	52.24	52.02	52.21	52.30	52.73	52.84	53.45	63.19	63.78
2034	59.54	59.50	56.03	53.52	53.30	53.50	53.59	54.04	54.15	54.77	64.76	65.39
2035	61.18	61.14	57.54	54.98	54.75	54.96	55.06	55.52	55.62	56.26	66.50	67.17
2036	62.67	62.62	58.96	56.35	56.12	56.33	56.43	56.89	57.00	57.65	68.09	68.78
2037	64.17	64.12	60.39	57.73	57.49	57.71	57.80	58.28	58.39	59.06	69.69	70.39
2038	65.73	65.69	61.88	59.17	58.93	59.15	59.25	59.73	59.85	60.52	71.37	72.08
2039	67.09	67.04	63.16	60.40	60.15	60.38	60.48	60.98	61.09	61.78	72.83	73.56
2040	68.83	68.78	64.83	62.01	61.76	61.99	62.09	62.60	62.72	63.42	74.68	75.42
2041	70.23	70.17	66.14	63.27	63.02	63.25	63.36	63.87	63.99	64.71	76.19	76.95

					T	ABLE 2a						
					Avoi	ided Cost	ts					
				Standard	Fixed P	rice Optic	on for Wi	nd QF				
				0	n-Peak F	orecast (\$/MWH)					
									_	-		
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	24.37	18.62	11.77	10.87	8.62	13.12	20.12	23.12	21.12	19.87	22.87	27.62
2017	26.05	24.30	20.80	17.05	15.55	16.55	24.05	27.05	25.55	23.80	24.80	29.80
2018	27.72	27.12	24.12	18.14	17.29	17.29	25.94	29.38	26.64	24.62	27.87	31.72
2019	29.87	27.88	23.90	19.63	17.93	19.06	27.60	31.01	29.30	27.31	28.45	34.14
2020	31.59	29.49	25.30	20.80	19.00	20.20	29.19	32.79	30.99	28.89	30.09	36.09
2021	30.68	30.59	28.66	27.94	27.66	27.75	27.87	27.99	28.10	28.74	31.86	31.98
2022	31.56	31.39	30.62	29.68	29.36	29.46	29.59	29.72	29.84	30.38	33.93	34.25
2023	33.67	33.48	32.11	30.91	30.79	30.90	31.03	31.17	31.30	31.84	35.28	35.42
2024	35.38	35.06	33.88	32.49	32.30	32.42	32.56	32.70	32.84	33.40	37.70	37.85
2025	37.53	37.64	36.18	35.22	35.36	35.48	35.64	35.81	35.96	36.14	42.91	43.23
2026	44.75	44.87	42.35	40.86	40.79	40.94	41.13	41.32	41.48	41.94	48.60	48.29
2027	45.65	45.56	43.93	41.91	41.68	41.82	41.79	42.12	42.26	42.76	50.18	49.94
2028	47.32	47.31	45.96	43.46	43.30	43.46	43.31	43.64	43.95	44.65	52.66	51.55
2029	51.25	51.18	48.43	45.94	45.16	45.34	44.90	45.25	45.80	46.53	55.57	55.30
2030	53.96	53.90	51.23	48.98	48.76	48.93	48.97	49.36	49.48	50.04	58.78	59.06
2031	55.08	55.02	52.29	50.00	49.77	49.95	49.99	50.38	50.51	51.08	59.99	60.28
2032	58.77	58.72	55.49	53.10	52.88	53.07	53.15	53.57	53.68	54.28	63.78	64.33
2033	60.35	60.30	56.96	54.51	54.29	54.49	54.57	55.00	55.11	55.72	65.46	66.05
2034	61.88	61.83	58.36	55.86	55.63	55.84	55.93	56.37	56.48	57.10	67.09	67.72
2035	63.54	63.49	59.90	57.34	57.11	57.32	57.42	57.87	57.98	58.62	68.86	69.53
2036	65.04	65.00	61.33	58.72	58.49	58.70	58.80	59.27	59.38	60.03	70.46	71.15
2037	66.61	66.57	62.83	60.17	59.93	60.15	60.25	60.73	60.84	61.50	72.14	72.84
2038	68.23	68.18	64.37	61.66	61.42	61.64	61.74	62.23	62.34	63.02	73.86	74.57
2039	69.64	69.59	65.71	62.94	62.70	62.92	63.03	63.52	63.64	64.33	75.38	76.11
2040	71.42	71.37	67.41	64.60	64.35	64.58	64.68	65.18	65.30	66.00	77.27	78.01
2041	72.87	72.82	68.79	65.92	65.66	65.90	66.00	66.52	66.64	67.35	78.84	79.59

					TA	ABLE 2b						
						ded Cos	ts					
				Standard	d Fixed P	rice Opti	on for Wi	ind QF				
				0	ff-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	21.77	16.87	10.12	7.57	2.47	6.27	11.87	17.12	17.12	17.37	19.62	22.87
2017	21.80	20.30	18.30	11.80	9.80	8.80	15.80	21.30	21.55	20.80	21.80	24.05
2018	22.18	24.13	21.57	15.47	10.69	8.55	15.72	23.05	22.94	21.36	24.21	26.63
2019	25.77	24.02	21.68	14.08	11.74	10.57	18.76	25.19	25.48	24.60	25.77	28.40
2020	27.60	25.73	23.23	15.13	12.64	11.39	20.12	26.97	27.28	26.35	27.60	30.40
2021	24.65	24.56	22.63	21.92	21.64	21.72	21.84	21.96	22.07	22.71	25.83	25.95
2022	25.42	25.25	24.48	23.54	23.22	23.32	23.44	23.57	23.69	24.23	27.78	28.11
2023	27.39	27.20	25.82	24.62	24.51	24.61	24.75	24.88	25.01	25.56	28.99	29.13
2024	29.01	28.69	27.51	26.13	25.94	26.05	26.19	26.34	26.48	27.04	31.33	31.49
2025	31.02	31.13	29.68	28.71	28.86	28.97	29.14	29.30	29.45	29.63	36.41	36.72
2026	38.12	38.24	35.71	34.22	34.16	34.30	34.50	34.69	34.85	35.30	41.97	41.66
2027	38.89	38.80	37.17	35.15	34.92	35.06	35.03	35.35	35.50	36.00	43.42	43.18
2028	40.43	40.42	39.07	36.57	36.40	36.57	36.42	36.75	37.06	37.76	45.77	44.65
2029	44.23	44.16	41.40	38.91	38.14	38.32	37.88	38.23	38.78	39.51	48.54	48.28
2030	46.80	46.74	44.07	41.82	41.60	41.77	41.81	42.20	42.32	42.88	51.62	51.90
2031	47.78	47.72	44.99	42.70	42.47	42.65	42.69	43.09	43.21	43.78	52.69	52.98
2032	51.38	51.33	48.10	45.71	45.49	45.68	45.76	46.18	46.29	46.89	56.39	56.94
2033	52.77	52.72	49.38	46.93	46.71	46.90	46.99	47.42	47.53	48.14	57.88	58.47
2034	54.12	54.08	50.61	48.10	47.88	48.08	48.17	48.62	48.73	49.35	59.34	59.97
2035	55.66	55.62	52.02	49.46	49.23	49.44	49.54	50.00	50.10	50.74	60.98	61.65
2036	57.04	56.99	53.33	50.72	50.49	50.70	50.80	51.26	51.37	52.02	62.46	63.15
2037	58.43	58.38	54.65	51.99	51.75	51.97	52.06	52.54	52.65	53.32	63.95	64.65
2038	59.88	59.84	56.03	53.32	53.08	53.30	53.40	53.88	54.00	54.67	65.52	66.23
2039	61.13	61.08	57.20	54.44	54.19	54.42	54.52	55.02	55.13	55.82	66.87	67.60
2040	62.75	62.70	58.75	55.93	55.68	55.91	56.01	56.52	56.64	57.34	68.60	69.34
2041	64.04	63.98	59.95	57.08	56.83	57.06	57.17	57.68	57.80	58.52	70.00	70.76

					T	ABLE 3a						
					Avoi	ded Cost	ts					
				Standard	l Fixed P	rice Optic	on for So	lar QF				
				0	n-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	28.21	22.46	15.61	14.71	12.46	16.96	23.96	26.96	24.96	23.71	26.71	31.46
2017	29.96	28.21	24.71	20.96	19.46	20.46	27.96	30.96	29.46	27.71	28.71	33.71
2018	31.71	31.11	28.11	22.13	21.28	21.28	29.93	33.37	30.63	28.61	31.86	35.71
2019	33.94	31.95	27.97	23.70	22.00	23.13	31.67	35.08	33.37	31.38	32.52	38.21
2020	35.74	33.64	29.45	24.95	23.15	24.35	33.34	36.94	35.14	33.04	34.24	40.24
2021	33.98	33.89	31.96	31.24	30.96	31.05	31.16	31.28	31.39	32.03	35.15	35.27
2022	34.92	34.75	33.98	33.04	32.72	32.82	32.94	33.08	33.20	33.74	37.28	37.61
2023	37.09	36.90	35.52	34.32	34.21	34.31	34.44	34.58	34.71	35.26	38.69	38.83
2024	38.86	38.54	37.36	35.98	35.79	35.90	36.04	36.19	36.32	36.88	41.18	41.33
2025	41.08	41.19	39.73	38.77	38.92	39.03	39.19	39.36	39.51	39.69	46.46	46.78
2026	48.37	48.49	45.97	44.48	44.42	44.56	44.75	44.94	45.10	45.56	52.22	51.91
2027	49.34	49.25	47.62	45.61	45.38	45.51	45.48	45.81	45.95	46.45	53.87	53.63
2028	51.08	51.07	49.72	47.22	47.06	47.22	47.07	47.40	47.72	48.41	56.42	55.31
2029	55.08	55.01	52.26	49.77	48.99	49.17	48.73	49.08	49.63	50.36	59.40	59.13
2030	57.87	57.81	55.14	52.89	52.67	52.84	52.88	53.27	53.39	53.95	62.69	62.97
2031	59.07	59.00	56.28	53.98	53.76	53.93	53.98	54.37	54.49	55.06	63.98	64.26
2032	62.83	62.78	59.56	57.16	56.94	57.13	57.21	57.64	57.75	58.34	67.85	68.39
2033	64.49	64.44	61.09	58.64	58.42	58.62	58.70	59.14	59.25	59.86	69.60	70.18
2034	66.10	66.05	62.58	60.08	59.85	60.05	60.14	60.59	60.70	61.32	71.31	71.94
2035	67.84	67.79	64.20	61.64	61.41	61.62	61.71	62.17	62.28	62.92	73.16	73.83
2036	69.43	69.38	65.72	63.11	62.88	63.09	63.19	63.66	63.77	64.42	74.85	75.54
2037	71.08	71.04	67.30	64.64	64.40	64.62	64.72	65.20	65.31	65.97	76.61	77.31
2038	72.78	72.73	68.93	66.22	65.98	66.20	66.30	66.78	66.90	67.57	78.42	79.13
2039	74.28	74.23	70.35	67.58	67.34	67.56	67.67	68.16	68.28	68.97	80.02	80.75
2040	76.15	76.10	72.15	69.33	69.08	69.31	69.42	69.92	70.04	70.74	82.01	82.75
2041	77.69	77.64	73.61	70.74	70.48	70.72	70.82	71.34	71.46	72.17	83.66	84.41

					TA	ABLE 3b						
					Avoi	ded Cost	ts					
				Standard	l Fixed P	rice Optic	on for So	lar QF				
				0	ff-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	25.61	20.71	13.96	11.41	6.31	10.11	15.71	20.96	20.96	21.21	23.46	26.71
2017	25.71	24.21	22.21	15.71	13.71	12.71	19.71	25.21	25.46	24.71	25.71	27.96
2018	26.17	28.12	25.56	19.46	14.68	12.54	19.71	27.04	26.93	25.35	28.20	30.62
2019	29.84	28.09	25.75	18.15	15.81	14.64	22.83	29.26	29.55	28.67	29.84	32.47
2020	31.75	29.88	27.38	19.28	16.79	15.54	24.27	31.12	31.43	30.50	31.75	34.55
2021	28.88	28.79	26.86	26.15	25.87	25.95	26.07	26.19	26.30	26.94	30.06	30.18
2022	29.73	29.56	28.79	27.85	27.53	27.63	27.75	27.88	28.00	28.54	32.09	32.42
2023	31.78	31.59	30.21	29.01	28.90	29.00	29.14	29.27	29.40	29.95	33.38	33.52
2024	33.48	33.16	31.98	30.60	30.41	30.52	30.66	30.81	30.95	31.51	35.80	35.96
2025	35.58	35.69	34.24	33.27	33.42	33.53	33.70	33.86	34.01	34.19	40.97	41.28
2026	42.77	42.89	40.36	38.87	38.81	38.95	39.15	39.34	39.50	39.95	46.62	46.31
2027	43.63	43.54	41.91	39.89	39.66	39.80	39.77	40.09	40.24	40.74	48.16	47.92
2028	45.26	45.25	43.90	41.40	41.23	41.40	41.25	41.58	41.89	42.59	50.60	49.48
2029	49.15	49.08	46.32	43.83	43.06	43.24	42.80	43.15	43.70	44.43	53.46	53.20
2030	51.82	51.76	49.09	46.84	46.62	46.79	46.83	47.22	47.34	47.90	56.64	56.92
2031	52.90	52.84	50.11	47.82	47.59	47.77	47.81	48.21	48.33	48.90	57.81	58.10
2032	56.59	56.54	53.31	50.92	50.70	50.89	50.97	51.39	51.50	52.10	61.60	62.15
2033	58.08	58.03	54.69	52.24	52.02	52.21	52.30	52.73	52.84	53.45	63.19	63.78
2034	59.54	59.50	56.03	53.52	53.30	53.50	53.59	54.04	54.15	54.77	64.76	65.39
2035	61.18	61.14	57.54	54.98	54.75	54.96	55.06	55.52	55.62	56.26	66.50	67.17
2036	62.67	62.62	58.96	56.35	56.12	56.33	56.43	56.89	57.00	57.65	68.09	68.78
2037	64.17	64.12	60.39	57.73	57.49	57.71	57.80	58.28	58.39	59.06	69.69	70.39
2038	65.73	65.69	61.88	59.17	58.93	59.15	59.25	59.73	59.85	60.52	71.37	72.08
2039	67.09	67.04	63.16	60.40	60.15	60.38	60.48	60.98	61.09	61.78	72.83	73.56
2040	68.83	68.78	64.83	62.01	61.76	61.99	62.09	62.60	62.72	63.42	74.68	75.42
2041	70.23	70.17	66.14	63.27	63.02	63.25	63.36	63.87	63.99	64.71	76.19	76.95

PRICING OPTIONS FOR STANDARD PPA (Continued)

2) Renewable Fixed Price Option

The Renewable Fixed Price Option is based on Renewable Avoided Costs. It is available only to Renewable QFs that generate electricity from a renewable energy source that may be used by the Company to comply with the Oregon Renewable Portfolio Standard as set forth in ORS 469A.005 to 469A.210.

This option is available for a maximum term of 15 years. Prices will be as established at the time the Standard PPA is executed and will be equal to the Renewable Avoided Costs in Tables 4a and 4b, 5a and 5b, or 6a and 6b, depending on the type of QF, effective at execution. QFs using any resource type other than wind and solar are assumed to be Base Load QFs.

Sellers will retain all Environmental Attributes generated by the facility during the Renewable Resource Sufficiency Period. A Renewable QF choosing the Renewable Fixed Price Option must cede all RPS Attributes generated by the facility to the Company from the start of the Renewable Resource Deficiency Period through the remainder of the PPA term.

Prices paid to the Seller under the Renewable Fixed Price Option include adjustments for the capacity contribution of the QF resource type relative to that of the avoided proxy resource. Both Wind QF resources (Tables 5a and 5b) and the avoided proxy resource, the basis used to determine Renewable Avoided Costs for the Renewable Fixed Price Option, are assumed to have a capacity contribution to peak of 5%. The capacity contribution for Solar QF resources (Tables 6a and 6b) is assumed to be 5%. The capacity contribution for Base Load QF resources (Tables 4a and 4b) is assumed to be 100%.

The Renewable Avoided Costs during the Renewable Resource Deficiency Period reflect an increase for avoided wind integration costs, shown in Table 7.

Prices paid to the Seller under the Renewable Fixed Price Option for Wind QFs (Tables 5a and 5b) include a reduction for the wind integration costs in Table 7, which cancels out wind integration costs included in the Renewable Avoided Costs during the Renewable Resource Deficiency Period. However, if the Wind QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the wind integration charges in Table 7, in addition to the prices listed in Tables 5a and 5b.

Sellers with PPAs exceeding 15 years will receive pricing equal to the Mid-C Index Price for all years up to five in excess of the initial 15.

	TABLE 4a												
				F	Renewabl	e Avoide	d Costs						
			Rei	newable l	Fixed Price	ce Option	for Base	e Load Q	F				
				0	n-Peak F	orecast (\$/MWH)						
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2016	28.36	22.61	15.76	14.86	12.61	17.11	24.11	27.11	25.11	23.86	26.86	31.61	
2017	30.11	28.36	24.86	21.11	19.61	20.61	28.11	31.11	29.61	27.86	28.86	33.86	
2018	31.86	31.26	28.26	22.28	21.43	21.43	30.08	33.52	30.78	28.76	32.01	35.86	
2019	34.10	32.11	28.13	23.86	22.16	23.29	31.83	35.24	33.53	31.54	32.68	38.37	
2020	115.34	115.32	114.56	115.02	118.22	117.33	117.01	116.89	115.60	114.63	115.47	114.45	
2021	117.94	118.18	116.67	117.75	120.59	119.83	119.26	119.77	118.26	117.25	118.55	117.22	
2022	120.48	120.36	118.46	120.19	123.17	122.14	121.69	121.65	120.55	119.55	120.98	119.53	
2023	123.26	122.83	120.85	122.92	125.37	124.64	124.29	123.92	123.08	121.92	123.63	122.53	
2024	124.86	125.01	123.06	125.07	127.80	126.78	126.67	126.41	126.22	123.83	124.83	124.96	
2025	127.73	128.05	125.86	128.21	131.66	130.48	129.53	129.66	128.84	126.59	127.76	127.41	
2026	130.91	130.58	129.12	131.30	135.76	132.28	132.28	132.69	132.40	129.34	131.17	130.23	
2027	133.47	133.03	131.38	133.50	139.48	134.88	134.51	135.95	134.79	131.96	133.26	132.78	
2028	135.95	134.91	132.89	136.24	141.79	136.93	137.64	137.65	136.77	134.76	135.84	135.06	
2029	138.81	138.57	135.91	139.29	149.30	140.74	140.82	140.82	140.86	137.50	138.32	138.21	
2030	141.68	141.39	139.11	142.00	153.18	145.20	143.05	142.93	144.31	140.18	140.75	140.79	
2031	144.29	143.79	142.17	145.52	156.10	149.27	145.71	146.65	146.86	143.04	144.15	143.71	
2032	146.51	146.00	144.35	147.76	158.51	151.58	147.95	148.91	149.13	145.24	146.37	145.92	
2033	149.91	149.40	147.71	151.19	162.18	155.09	151.39	152.37	152.59	148.62	149.77	149.31	
2034	152.96	152.43	150.71	154.26	165.46	158.24	154.46	155.46	155.68	151.64	152.81	152.35	
2035	155.76	155.22	153.46	157.08	168.50	161.14	157.29	158.31	158.54	154.41	155.60	155.13	
2036	158.31	157.76	155.97	159.65	171.26	163.78	159.86	160.90	161.13	156.94	158.15	157.67	
2037	161.83	161.27	159.44	163.20	175.07	167.42	163.42	164.48	164.71	160.43	161.67	161.18	
2038	164.95	164.38	162.52	166.35	178.45	170.65	166.57	167.65	167.89	163.52	164.79	164.29	
2039	168.13	167.55	165.66	169.56	181.89	173.94	169.79	170.89	171.13	166.68	167.97	167.46	
2040	171.05	170.46	168.54	172.51	185.04	176.96	172.74	173.85	174.10	169.58	170.89	170.37	
2041	174.69	174.08	172.11	176.17	188.98	180.72	176.40	177.55	177.80	173.18	174.52	173.99	

					T	ABLE 4b						
				R	Renewabl	e Avoide	d Costs					
			Rer	newable F	ixed Pric	e Option	for Base	Load Q	F			
				0	ff-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	25.76	20.86	14.11	11.56	6.46	10.26	15.86	21.11	21.11	21.36	23.61	26.86
2017	25.86	24.36	22.36	15.86	13.86	12.86	19.86	25.36	25.61	24.86	25.86	28.11
2018	26.32	28.27	25.71	19.61	14.83	12.69	19.86	27.19	27.08	25.50	28.35	30.77
2019	30.00	28.25	25.91	18.31	15.97	14.80	22.99	29.42	29.71	28.83	30.00	32.63
2020	62.76	63.02	64.56	63.31	59.92	60.16	60.45	61.61	62.52	63.74	63.55	63.99
2021	64.93	64.15	65.85	64.48	61.58	61.62	62.27	62.62	63.78	65.82	63.38	65.09
2022	65.85	65.52	67.77	65.49	62.45	62.82	64.33	63.35	65.00	67.04	64.42	66.29
2023	66.70	66.75	69.10	67.28	62.84	64.01	65.40	64.85	66.14	68.41	65.38	67.63
2024	67.25	67.31	70.47	67.09	63.18	65.92	64.75	65.12	66.62	68.68	67.42	68.05
2025	68.62	68.60	71.94	68.08	63.17	66.28	66.12	67.12	67.23	70.19	69.68	69.06
2026	68.95	69.85	72.28	68.56	63.85	67.22	67.05	67.75	67.05	71.12	69.85	69.89
2027	71.31	71.29	73.13	70.34	63.69	68.45	68.79	68.16	68.57	73.22	70.67	71.18
2028	72.28	72.90	75.41	72.10	63.09	69.98	70.15	68.82	70.20	73.79	71.48	73.41
2029	72.78	73.60	76.79	73.50	58.25	70.29	71.37	70.00	71.53	74.58	73.61	74.68
2030	73.91	74.82	78.36	73.64	58.00	70.89	72.02	72.19	72.00	75.99	75.36	76.23
2031	75.51	76.70	79.40	74.00	59.17	70.67	73.55	73.71	72.16	77.24	77.07	76.31
2032	76.76	77.97	80.71	75.23	60.15	71.83	74.76	74.93	73.35	78.52	78.34	77.57
2033	78.46	79.69	82.50	76.89	61.48	73.42	76.42	76.58	74.97	80.25	80.07	79.29
2034	79.97	81.23	84.09	78.37	62.66	74.84	77.89	78.06	76.42	81.80	81.62	80.82
2035	81.52	82.80	85.71	79.88	63.87	76.28	79.39	79.57	77.89	83.38	83.19	82.38
2036	82.86	84.17	87.13	81.20	64.93	77.54	80.70	80.88	79.18	84.76	84.57	83.74
2037	84.69	86.03	89.05	83.00	66.36	79.25	82.49	82.67	80.93	86.63	86.44	85.59
2038	86.33	87.69	90.77	84.60	67.64	80.78	84.08	84.26	82.49	88.30	88.11	87.24
2039	87.99	89.38	92.52	86.23	68.95	82.34	85.70	85.89	84.08	90.01	89.81	88.92
2040	89.45	90.85	94.05	87.66	70.09	83.70	87.12	87.31	85.47	91.49	91.29	90.39
2041	91.42	92.86	96.13	89.59	71.63	85.55	89.04	89.24	87.36	93.51	93.31	92.39

					T.	ABLE 5a						
				F	Renewabl	e Avoide	d Costs					
				Renewab	le Fixed F	Price Opt	ion for W	ind QF				
				0	n-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	24.52	18.77	11.92	11.02	8.77	13.27	20.27	23.27	21.27	20.02	23.02	27.77
2017	26.20	24.45	20.95	17.20	15.70	16.70	24.20	27.20	25.70	23.95	24.95	29.95
2018	27.87	27.27	24.27	18.29	17.44	17.44	26.09	29.53	26.79	24.77	28.02	31.87
2019	30.03	28.04	24.06	19.79	18.09	19.22	27.76	31.17	29.46	27.47	28.61	34.30
2020	75.38	75.37	74.61	75.06	78.26	77.37	77.05	76.93	75.64	74.67	75.51	74.49
2021	77.10	77.33	75.83	76.90	79.75	78.99	78.41	78.92	77.41	76.40	77.70	76.38
2022	78.85	78.72	76.82	78.56	81.53	80.51	80.05	80.02	78.92	77.92	79.34	77.90
2023	80.71	80.27	78.29	80.37	82.82	82.08	81.73	81.37	80.53	79.36	81.08	79.97
2024	81.74	81.89	79.93	81.95	84.68	83.66	83.55	83.28	83.10	80.71	81.71	81.84
2025	83.64	83.97	81.78	84.13	87.57	86.40	85.44	85.57	84.75	82.51	83.68	83.32
2026	85.97	85.64	84.18	86.37	90.82	87.34	87.34	87.75	87.46	84.40	86.23	85.29
2027	87.67	87.23	85.57	87.69	93.67	89.07	88.71	90.15	88.99	86.16	87.45	86.98
2028	89.26	88.22	86.20	89.55	95.10	90.24	90.95	90.96	90.08	88.07	89.15	88.37
2029	91.22	90.98	88.32	91.70	101.72	93.16	93.23	93.23	93.28	89.92	90.73	90.62
2030	93.17	92.88	90.60	93.49	104.67	96.69	94.54	94.42	95.80	91.67	92.24	92.28
2031	94.84	94.34	92.72	96.07	106.65	99.82	96.26	97.20	97.42	93.59	94.70	94.26
2032	96.40	95.90	94.24	97.65	108.40	101.47	97.85	98.80	99.02	95.13	96.26	95.82
2033	98.55	98.03	96.34	99.82	110.81	103.72	100.02	101.00	101.22	97.25	98.40	97.95
2034	100.44	99.91	98.19	101.74	112.94	105.72	101.94	102.94	103.17	99.12	100.29	99.83
2035	102.38	101.85	100.09	103.71	115.13	107.76	103.92	104.93	105.16	101.04	102.23	101.76
2036	104.06	103.51	101.72	105.40	117.01	109.53	105.61	106.65	106.88	102.69	103.90	103.42
2037	106.37	105.81	103.99	107.74	119.61	111.96	107.96	109.02	109.26	104.97	106.21	105.72
2038	108.42	107.86	105.99	109.82	121.92	114.12	110.05	111.12	111.37	107.00	108.26	107.76
2039	110.52	109.94	108.04	111.95	124.27	116.33	112.17	113.27	113.52	109.07	110.36	109.85
2040	112.32	111.73	109.81	113.77	126.31	118.23	114.00	115.12	115.37	110.85	112.16	111.64
2041	114.83	114.23	112.26	116.31	129.12	120.86	116.55	117.69	117.95	113.32	114.66	114.13

TABLE 5b												
Renewable Avoided Costs												
Renewable Fixed Price Option for Wind QF												
Off-Peak Forecast (\$/MWH)												
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	21.92	17.02	10.27	7.72	2.62	6.42	12.02	17.27	17.27	17.52	19.77	23.02
2017	21.95	20.45	18.45	11.95	9.95	8.95	15.95	21.45	21.70	20.95	21.95	24.20
2018	22.33	24.28	21.72	15.62	10.84	8.70	15.87	23.20	23.09	21.51	24.36	26.78
2019	25.93	24.18	21.84	14.24	11.90	10.73	18.92	25.35	25.64	24.76	25.93	28.56
2020	58.61	58.87	60.41	59.16	55.77	56.01	56.30	57.46	58.37	59.59	59.40	59.84
2021	60.70	59.92	61.62	60.25	57.35	57.39	58.04	58.39	59.55	61.59	59.15	60.86
2022	61.54	61.21	63.46	61.18	58.14	58.51	60.02	59.04	60.69	62.73	60.11	61.98
2023	62.31	62.36	64.71	62.89	58.45	59.62	61.01	60.46	61.75	64.02	60.99	63.24
2024	62.78	62.84	66.00	62.62	58.71	61.45	60.28	60.65	62.15	64.21	62.95	63.58
2025	64.06	64.04	67.38	63.52	58.61	61.72	61.56	62.56	62.67	65.63	65.12	64.50
2026	64.30	65.20	67.63	63.91	59.20	62.57	62.40	63.10	62.40	66.47	65.20	65.24
2027	66.57	66.55	68.39	65.60	58.95	63.71	64.05	63.42	63.83	68.48	65.93	66.44
2028	67.45	68.07	70.58	67.27	58.26	65.15	65.32	63.99	65.37	68.96	66.65	68.58
2029	67.86	68.68	71.87	68.58	53.33	65.37	66.45	65.08	66.61	69.66	68.69	69.76
2030	68.89	69.80	73.34	68.62	52.98	65.87	67.00	67.17	66.98	70.97	70.34	71.21
2031	70.39	71.58	74.28	68.88	54.05	65.55	68.43	68.59	67.04	72.12	71.95	71.19
2032	71.55	72.76	75.50	70.02	54.94	66.62	69.55	69.72	68.14	73.31	73.13	72.36
2033	73.15	74.38	77.19	71.58	56.17	68.11	71.11	71.27	69.66	74.94	74.76	73.98
2034	74.55	75.81	78.67	72.95	57.24	69.42	72.47	72.64	71.00	76.38	76.20	75.40
2035	76.00	77.28	80.19	74.36	58.35	70.76	73.87	74.05	72.37	77.86	77.67	76.86
2036	77.23	78.54	81.50	75.57	59.30	71.91	75.07	75.25	73.55	79.13	78.94	78.11
2037	78.95	80.29	83.31	77.26	60.62	73.51	76.75	76.93	75.19	80.89	80.70	79.85
2038	80.48	81.84	84.92	78.75	61.79	74.93	78.23	78.41	76.64	82.45	82.26	81.39
2039	82.03	83.42	86.56	80.27	62.99	76.38	79.74	79.93	78.12	84.05	83.85	82.96
2040	83.37	84.77	87.97	81.58	64.01	77.62	81.04	81.23	79.39	85.41	85.21	84.31
2041	85.23	86.67	89.94	83.40	65.44	79.36	82.85	83.05	81.17	87.32	87.12	86.20

TABLE 6a												
Renewable Avoided Costs												
Renewable Fixed Price Option for Solar QF												
On-Peak Forecast (\$/MWH)												
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	28.36	22.61	15.76	14.86	12.61	17.11	24.11	27.11	25.11	23.86	26.86	31.61
2017	30.11	28.36	24.86	21.11	19.61	20.61	28.11	31.11	29.61	27.86	28.86	33.86
2018	31.86	31.26	28.26	22.28	21.43	21.43	30.08	33.52	30.78	28.76	32.01	35.86
2019	34.10	32.11	28.13	23.86	22.16	23.29	31.83	35.24	33.53	31.54	32.68	38.37
2020	78.62	78.60	77.84	78.30	81.50	80.60	80.29	80.17	78.88	77.91	78.74	77.73
2021	80.39	80.63	79.12	80.20	83.04	82.28	81.71	82.22	80.71	79.70	81.00	79.67
2022	82.21	82.08	80.18	81.92	84.89	83.87	83.41	83.38	82.27	81.27	82.70	81.25
2023	84.12	83.69	81.71	83.78	86.23	85.50	85.15	84.78	83.94	82.78	84.50	83.39
2024	85.22	85.37	83.41	85.43	88.16	87.14	87.03	86.76	86.58	84.19	85.19	85.32
2025	87.19	87.52	85.33	87.68	91.12	89.95	88.99	89.12	88.30	86.06	87.23	86.87
2026	89.59	89.26	87.80	89.99	94.44	90.96	90.96	91.37	91.08	88.02	89.85	88.91
2027	91.36	90.92	89.26	91.39	97.36	92.76	92.40	93.84	92.68	89.85	91.14	90.67
2028	93.02	91.98	89.96	93.31	98.86	94.00	94.71	94.72	93.84	91.84	92.91	92.13
2029	95.05	94.81	92.15	95.53	105.55	96.99	97.06	97.06	97.11	93.75	94.56	94.45
2030	97.08	96.79	94.51	97.40	108.58	100.60	98.45	98.33	99.71	95.58	96.15	96.19
2031	98.83	98.33	96.70	100.05	110.63	103.81	100.25	101.19	101.40	97.58	98.69	98.25
2032	100.47	99.96	98.30	101.71	112.47	105.53	101.91	102.87	103.08	99.20	100.32	99.88
2033	102.68	102.16	100.47	103.95	114.95	107.86	104.16	105.14	105.36	101.38	102.53	102.08
2034	104.66	104.13	102.41	105.96	117.16	109.94	106.16	107.16	107.38	103.34	104.51	104.05
2035	106.68	106.15	104.39	108.01	119.43	112.06	108.21	109.23	109.46	105.34	106.53	106.06
2036	108.44	107.90	106.11	109.79	121.40	113.91	110.00	111.04	111.27	107.08	108.29	107.81
2037	110.84	110.28	108.46	112.21	124.08	116.43	112.43	113.49	113.73	109.44	110.68	110.19
2038	112.98	112.41	110.55	114.38	126.47	118.68	114.60	115.68	115.92	111.55	112.82	112.32
2039	115.16	114.58	112.68	116.59	128.92	120.97	116.81	117.91	118.16	113.71	115.00	114.49
2040	117.06	116.47	114.54	118.51	131.04	122.96	118.74	119.86	120.11	115.58	116.89	116.37
2041	119.65	119.05	117.07	121.13	133.94	125.68	121.37	122.51	122.76	118.14	119.48	118.95

TABLE 6b												
Renewable Avoided Costs												
Renewable Fixed Price Option for Solar QF												
Off-Peak Forecast (\$/MWH)												
									_			
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	25.76	20.86	14.11	11.56	6.46	10.26	15.86	21.11	21.11	21.36	23.61	26.86
2017	25.86	24.36	22.36	15.86	13.86	12.86	19.86	25.36	25.61	24.86	25.86	28.11
2018	26.32	28.27	25.71	19.61	14.83	12.69	19.86	27.19	27.08	25.50	28.35	30.77
2019	30.00	28.25	25.91	18.31	15.97	14.80	22.99	29.42	29.71	28.83	30.00	32.63
2020	62.76	63.02	64.56	63.31	59.92	60.16	60.45	61.61	62.52	63.74	63.55	63.99
2021	64.93	64.15	65.85	64.48	61.58	61.62	62.27	62.62	63.78	65.82	63.38	65.09
2022	65.85	65.52	67.77	65.49	62.45	62.82	64.33	63.35	65.00	67.04	64.42	66.29
2023	66.70	66.75	69.10	67.28	62.84	64.01	65.40	64.85	66.14	68.41	65.38	67.63
2024	67.25	67.31	70.47	67.09	63.18	65.92	64.75	65.12	66.62	68.68	67.42	68.05
2025	68.62	68.60	71.94	68.08	63.17	66.28	66.12	67.12	67.23	70.19	69.68	69.06
2026	68.95	69.85	72.28	68.56	63.85	67.22	67.05	67.75	67.05	71.12	69.85	69.89
2027	71.31	71.29	73.13	70.34	63.69	68.45	68.79	68.16	68.57	73.22	70.67	71.18
2028	72.28	72.90	75.41	72.10	63.09	69.98	70.15	68.82	70.20	73.79	71.48	73.41
2029	72.78	73.60	76.79	73.50	58.25	70.29	71.37	70.00	71.53	74.58	73.61	74.68
2030	73.91	74.82	78.36	73.64	58.00	70.89	72.02	72.19	72.00	75.99	75.36	76.23
2031	75.51	76.70	79.40	74.00	59.17	70.67	73.55	73.71	72.16	77.24	77.07	76.31
2032	76.76	77.97	80.71	75.23	60.15	71.83	74.76	74.93	73.35	78.52	78.34	77.57
2033	78.46	79.69	82.50	76.89	61.48	73.42	76.42	76.58	74.97	80.25	80.07	79.29
2034	79.97	81.23	84.09	78.37	62.66	74.84	77.89	78.06	76.42	81.80	81.62	80.82
2035	81.52	82.80	85.71	79.88	63.87	76.28	79.39	79.57	77.89	83.38	83.19	82.38
2036	82.86	84.17	87.13	81.20	64.93	77.54	80.70	80.88	79.18	84.76	84.57	83.74
2037	84.69	86.03	89.05	83.00	66.36	79.25	82.49	82.67	80.93	86.63	86.44	85.59
2038	86.33	87.69	90.77	84.60	67.64	80.78	84.08	84.26	82.49	88.30	88.11	87.24
2039	87.99	89.38	92.52	86.23	68.95	82.34	85.70	85.89	84.08	90.01	89.81	88.92
2040	89.45	90.85	94.05	87.66	70.09	83.70	87.12	87.31	85.47	91.49	91.29	90.39
2041	91.42	92.86	96.13	89.59	71.63	85.55	89.04	89.24	87.36	93.51	93.31	92.39

WIND INTEGRATION

TAE	BLE 7							
Wind Integration								
Year	Cost							
2015	3.77							
2016	3.84							
2017	3.91							
2018	3.99							
2019	4.07							
2020	4.15							
2021	4.23							
2022	4.31							
2023	4.39							
2024	4.47							
2025	4.56							
2026	4.65							
2027	4.74							
2028	4.83							
2029	4.92							
2030	5.02							
2031	5.12							
2032	5.21							
2033	5.31							
2034	5.42							
2035	5.52							
2036	5.63							
2037	5.74							
2038	5.85							
2039	5.96							
2040	6.08							

MONTHLY SERVICE CHARGE

Each separately metered QF not associated with a retail Customer account will be charged \$10.00 per month.

INSURANCE REQUIREMENTS

The following insurance requirements are applicable to Sellers with a Standard PPA:

- 1) QFs with nameplate capacity ratings greater than 200 kW are required to secure and maintain a prudent amount of general liability insurance. The Seller must certify to the Company that it is maintaining general liability insurance coverage for each QF at prudent amounts. A prudent amount will be deemed to mean liability insurance coverage for both bodily injury and property damage liability in the amount of not less than \$1,000,000 each occurrence combined single limit, which limits may be required to be increased or decreased by the Company as the Company determines in its reasonable judgment, that economic conditions or claims experience may warrant.
- Such insurance will include an endorsement naming the Company as an additional insured insofar as liability arising out of operations under this schedule and a provision that such liability policies will not be canceled or their limits reduced without 30 days' written notice to the Company. The Seller will furnish the Company with certificates of insurance together with the endorsements required herein. The Company will have the right to inspect the original policies of such insurance.
- 3) QFs with a design capacity of 200 kW or less are encouraged to pursue liability insurance on their own. The Oregon Public Utility Commission in Order No. 05-584 determined that it is inappropriate to require QFs that have a design capacity of 200 kW or less to obtain general liability insurance.

TRANSMISSION AGREEMENTS

If the QF is located outside the Company's service territory, the Seller is responsible for the transmission of power at its cost to the Company's service territory.

INTERCONNECTION REQUIREMENTS

Except as otherwise provided in a generation Interconnection Agreement between the Company and Seller, if the QF is located within the Company's service territory, switching equipment capable of isolating the QF from the Company's system will be accessible to the Company at all times. At the Company's option, the Company may operate the switching equipment described above if, in the sole opinion of the Company, continued operation of the QF in connection with the utility's system may create or contribute to a system emergency.

INTERCONNECTION REQUIREMENTS (Continued)

The QF owner interconnecting with the Company's distribution system must comply with all requirements for interconnection as established pursuant to Commission rule, in the Company's Rules and Regulations (Rule C) or the Company's Interconnection Procedures contained in its FERC Open Access Transmission Tariff (OATT), as applicable. The Seller will bear full responsibility for the installation and safe operation of the interconnection facilities.

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE PRICING UNDER THE STANDARD PPA

A QF will be eligible to receive pricing under the Standard PPA if the nameplate capacity of the QF, together with any other electric generating facility using the same motive force, owned or controlled by the Same Person(s) or Affiliated Person(s), and located at the Same Site, does not exceed 10 MW. A Community-Based or Family-Owned QF is exempt from these restrictions.

Definition of Community-Based

- a. A community project (or a community sponsored project) must have a recognized and established organization located within the county of the project or within 50 miles of the project that has a genuine role in helping the project be developed and must have some not insignificant continuing role with or interest in the project after it is completed and placed in service.
- b. After excluding the passive investor whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit, the equity (ownership) interests in a community sponsored project must be owned in substantial percentage (80 percent or more) by the following persons (individuals and entities): (i) the sponsoring organization, or its controlled affiliates; (ii) members of the sponsoring organization (if it is a membership organization) or owners of the sponsorship organization (if it is privately owned); (iii) persons who live in the county in which the project is located or who live a county adjoining the county in which the project is located; or (iv) units of local government, charities, or other established nonprofit organizations active either in the county in which the project is located or active in a county adjoining the county in which the project is located.

Definition of Family-Owned

After excluding the ownership interest of the passive investor whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit, five or fewer individuals own 50 percent or more of the equity of the project entity, or fifteen or fewer individuals own 90 percent or more of the project entity. A "look through" rule applies to closely held entities that hold the project entity, so that equity held by LLCs, trusts, estates, corporations, partnerships or other similar entities is considered held by the equity owners of the look through entity. An individual is a natural person. In counting to five or fifteen, spouses or children of an equity owner of the project owner who also have an equity interest are aggregated and counted as a single individual.

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE PRICING UNDER THE STANDARD PPA (Continued)

Definition of Person(s) or Affiliated Person(s)

As used above, the term "Same Person(s)" or "Affiliated Person(s)" means a natural person or persons or any legal entity or entities sharing common ownership, management or acting jointly or in concert with or exercising influence over the policies or actions of another person or entity. However, two facilities will not be held to be owned or controlled by the Same Person(s) or Affiliated Person(s) solely because they are developed by a single entity.

Furthermore, two facilities will not be held to be owned or controlled by the Same Person(s) or Affiliated Person(s) if such common person or persons is a "passive investor" whose ownership interest in the QF is primarily related to utilizing production tax credits, green tag values and MACRS depreciation as the primary ownership benefit and the facilities at issue are independent family-owned or community-based projects. A unit of Oregon local government may also be a "passive investor" in a community-based project if the local governmental unit demonstrates that it will not have an equity ownership interest in or exercise any control over the management of the QF and that its only interest is a share of the cash flow from the QF, which share will not exceed 20%. The 20% cash flow share limit may only be exceeded for good cause shown and only with the prior approval of the Commission.

Definition of Same Site

For purposes of the foregoing, generating facilities are considered to be located at the same site as the QF for which qualification for pricing under the Standard PPA is sought if they are located within a five-mile radius of any generating facilities or equipment providing fuel or motive force associated with the QF for which qualification for pricing under the Standard PPA is sought.

Definition of Shared Interconnection and Infrastructure

QFs otherwise meeting the above-described separate ownership test and thereby qualified for entitlement to pricing under the Standard PPA will not be disqualified by utilizing an interconnection or other infrastructure not providing motive force or fuel that is shared with other QFs qualifying for pricing under the Standard PPA so long as the use of the shared interconnection complies with the interconnecting utility's safety and reliability standards, interconnection agreement requirements and Prudent Electrical Practices as that term is defined in the interconnecting utility's approved Standard PPA.

OTHER DEFINITIONS

Mid-C Index Price

As used in this schedule, the daily Mid-C Index Price shall be the Day Ahead Intercontinental Exchange ("ICE") for the bilateral OTC market for energy at the Mid-C Physical for Average

OTHER DEFINITIONS (Continued)

On-Peak Power and Average Off-Peak Power found on the following website: https://www.theice.com/products/OTC/Physical-Energy/Electricity. In the event ICE no longer publishes this index, PGE and the Seller agree to select an alternative successor index representative of the Mid-C trading hub.

Definition of RPS Attributes

As used in this schedule, RPS Attributes means all attributes related to the Net Output generated by the Facility that are required in order to provide PGE with "qualifying electricity," as that term is defined in Oregon's Renewable Portfolio Standard Act, Ore. Rev. Stat. 469A.010, in effect at the time of execution of this Agreement. RPS Attributes do not include Environmental Attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity and not needed to ensure that there are zero net emissions associated with the generation of electricity.

Definition of Environmental Attributes

As used in this schedule, Environmental Attributes shall mean any and all claims, credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical, or other substance to the air, soil or water. Environmental Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil, or water such as (subject to the foregoing) sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; and (2) any avoided emissions of carbon dioxide (CO2), methane (CH4), and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere.

Definition of Resource Sufficiency Period

This is the period from the current year through 2020.

Definition of Resource Deficiency Period

This is the period from 2021 through 2034.

Definition of Renewable Resource Sufficiency Period

This is the period from the current year through 2019.

Definition of Renewable Resource Deficiency Period

This is the period from 2020 through 2034.

SCHEDULE 201 (Concluded)

DISPUTE RESOLUTION

Upon request, the QF will provide the purchasing utility with documentation verifying the ownership, management and financial structure of the QF in reasonably sufficient detail to allow the utility to make an initial determination of whether or not the QF meets the above-described criteria for entitlement to pricing under the Standard PPA.

The QF may present disputes to the Commission for resolution using the following process:

The QF may file a complaint asking the Commission to adjudicate disputes regarding the formation of the standard contract. The QF may not file such a complaint during any 15-day period in which the utility has the obligation to respond, but must wait until the 15-day period has passed.

The utility may respond to the complaint within ten days of service.

The Commission will limit its review to the issues identified in the complaint and response, and utilize a process similar to the arbitration process adopted to facilitate the execution of interconnection agreements among telecommunications carriers. See OAR 860, Division 016. The administrative law judge will not act as an arbitrator.

SPECIAL CONDITIONS

- 1. Delivery of energy by Seller will be at a voltage, phase, frequency, and power factor as specified by the Company.
- 2. If the Seller also receives retail Electricity Service from the Company at the same location, any payments under this schedule will be credited to the Seller's retail Electricity Service bill. At the option of the Customer, any net credit over \$10.00 will be paid by check to the Customer.
- 3. Unless required by state or federal law, if the 1978 Public Utility Regulatory Policies Act (PURPA) is repealed, PPAs entered into pursuant to this schedule will not terminate prior to the Standard or Negotiated PPA's termination date.

TERM OF AGREEMENT

Not less than one year and not to exceed 20 years.

From: Angeline Chong <Angeline.Chong@pgn.com>

Sent: Wednesday, March 22, 2017 11:27 AM

To: Talbott, Will

Subject: EDP Renewables Blue Marmot VIII Draft PPA

Attachments: Final Draft and sched Ren Off Sys Blue Marmot VIII.pdf; Cover letter Final Draft PPA.pdf

Please see the attached. Thanks.



March 22, 2017

Will Talbott EDP Renewables north America LLC Development-Western Region 53 SW Yamhill Street, Portland OR 97204 will.talbott@epdr.com

RE: Transmittal of Final Draft Standard PPA

Blue Marmot VIII project, a proposed 10 megawatt Solar QF

Dear Mr. Tabott,

Thank you for your interest in entering into a Standard Power Purchase Agreement (Standard PPA) with Portland General Electric (PGE). We received your written request for a final draft Standard PPA on March 1, 2107. PGE has determined that you have provided sufficient information to allow PGE to prepare a final draft Standard PPA.

Enclosed please find a final draft Standard PPA for your **Blue Marmot VIII** project, 10 megawatt **Solar** generating facility that was self certified as a qualifying facility (QF) pursuant to 18 CFR 292.207. PGE understands that **Blue Marmot VIII**, **LLC** a limited liability company formed under the laws of the State of **Delaware** is the owner of the **Blue Marmot VIII** project and will be the Seller under the Standard PPA. If any of this information or any of the factual details contained in the enclosed final draft Standard PPA are incorrect or change, please inform PGE immediately.

The enclosed final draft Standard PPA is a discussion draft; it is not a binding offer and PGE reserves the right to revise any of its variable terms, including exhibits. No binding Standard PPA will exist between PGE and Blue Marmot VIII, LLC unless and until PGE has provided Blue Marmot VIII, LLC with an executable Standard PPA and both Blue Marmot VIII, LLC and PGE have executed the document.

At this stage in the process you have several options: you can decide not to pursue a contract any further; you can propose in writing substantive changes to your project proposal or to the variable terms of the final draft Standard PPA; or you can send PGE a written request to prepare an executable Standard PPA without proposing any substantive changes to your project or the final draft contract.

If you propose substantive changes to your project or the variable terms of the final draft Standard PPA, PGE will treat your proposal as a new request for a draft Standard PPA. Within 15 business days of receiving your written proposal, PGE with send you either a new draft Standard PPA or PGE will request additional or clarifying information if PGE

Mr. Talbott March 22, 2017 Page 2 of 2

reasonably determines that it requires more information before it can prepare a new draft Standard PPA in response to your proposal to change contract terms or project details.

If you request an executable Standard PPA without proposing substantive changes to your project proposal or the variable terms of the final draft Standard PPA, then within 15 business days of receiving your written request, PGE will send you either an executable Standard PPA or request additional or clarifying information if PGE reasonably determines that additional information is necessary to prepare an executable Standard PPA.

Once you receive an executable Standard PPA, you can execute it without alteration and establish a legally enforceable obligation. Pursuant to PGE's Schedule 201 at Sheet No. 201-3 and OPUC Order No. 16-174 at 3, the power purchase prices you are entitled to receive under your Standard PPA will be based on PGE's Standard Avoided Costs or Renewable Avoided Costs in effect at the time that you execute an executable Standard PPA provided to you by PGE.

This letter summarizes certain aspects of the Standard PPA process; it does not address every detail of the process. Additional details will be provided for each stage in PGE's letters associated with each stage. If you have any questions, please contact PGE's Power Production Coordinator at (503) 464-8000.

Sincerely,

Angeline D. Chong

angel

Portland General Electric

121 SW Salmon St. 3WTC0306 | Portland, Oregon 97204|

W: 503-464-7343 | F: 503-464-2605 |

E: angeline.chong@pgn.com

enclosure: Final Draft Standard PPA for Blue Marmot VIII LLC's Blue Marmot VIII

Project

STANDARD RENEWABLE OFF-SYSTEM VARIABLE POWER PURCHASE AGREEMENT

THIS AGREEMENT is between **Blue Marmot VIII LLC** ("Seller") and Portland General Electric Company ("PGE") (hereinafter each a "Party" or collectively, "Parties") and is effective upon execution by both Parties ("Effective Date").

RECITALS

Seller intends to construct, own, operate and maintain a **Solar** facility for the generation of electric power located in **Lake County, W -120.556, N 42.197** County, **Oregon** with a Nameplate Capacity Rating of **10000** kilowatt ("kW"), as further described in Exhibit A ("Facility"); and

Seller intends to operate the Facility as a "Qualifying Facility," as such term is defined in Section 3.1.3, below.

Seller shall sell and PGE shall purchase the entire Net Output, as such term is defined in Section 1.21, below, from the Facility in accordance with the terms and conditions of this Agreement.

AGREEMENT

NOW, THEREFORE, the Parties mutually agree as follows:

SECTION 1: DEFINITIONS

When used in this Agreement, the following terms shall have the following meanings:

- 1.1. "As-built Supplement" means the supplement to Exhibit A provided by Seller in accordance with Section 4.3 following completion of construction of the Facility, describing the Facility as actually built.
- 1.2. "Base Hours" is defined as the total number of hours in each Contract Year (8,760 or 8,784 for leap year)
- 1.3. "Billing Period" means from the start of the first day of each calendar month to the end of the last day of each calendar month.
- 1.4. "Cash Escrow" means an agreement by two parties to place money into the custody of a third party for delivery to a grantee only after the fulfillment of the conditions specified.
- 1.5. "Commercial Operation Date" means the date that the Facility is deemed by PGE to be fully operational and reliable. PGE may, at its discretion require, among other things, that all of the following events have occurred:
- 1.5.1. (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from a Licensed

Professional Engineer ("LPE") acceptable to PGE in its reasonable judgment stating that the Facility is able to generate electric power reliably in accordance with the terms and conditions of this Agreement (certifications required under this Section 1.5 can be provided by one or more LPEs);

- 1.5.2. Start-Up Testing of the Facility has been completed in accordance with Section 1.36;
- 1.5.3. (facilities with nameplate under 500 kW exempt from following requirement) After PGE has received notice of completion of Start-Up Testing, PGE has received a certificate addressed to PGE from an LPE stating that the Facility has operated for testing purposes under this Agreement and was continuously mechanically available for operation for a minimum of 120 hours. The Facility must provide ten (10) working days written notice to PGE prior to the start of the initial testing period. If the mechanical availability of the Facility is interrupted during this initial testing period or any subsequent testing period, the Facility shall promptly start a new Test Period and provide PGE forty-eight (48) hours written notice prior to the start of such testing period;
- 1.5.4. (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from an LPE stating that all required interconnection facilities have been constructed and all required interconnection tests have been completed;
- 1.5.5. (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from an LPE stating that Seller has obtained all Required Facility Documents and, if requested by PGE in writing, has provided copies of any or all such requested Required Facility Documents;
- 1.5.6. PGE has received a copy of the executed Generation Interconnection and Transmission Agreements.
- 1.6. "Contract Price" means the applicable price, including on-peak and off-peak prices, as specified in the Schedule.
- 1.7. "Contract Year" means each twelve (12) month period commencing upon the Commercial Operation Date or its anniversary during the Term, except the final Contract Year will be the period from the last anniversary of the Commercial Operation Date during the Term until the end of the Term.
 - 1.8. "Effective Date" has the meaning set forth in Section 2.1.
- 1.9. "Environmental Attributes" shall mean any and all claims, credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical or other substance to the air, soil or water. Environmental Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil or water such as (subject to the foregoing) sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; and (2) any avoided emissions of carbon dioxide (CO2), methane (CH4), and other greenhouse gasses (GHGs) that have been determined by the United Nations

Intergovernmental Panel on Climate Change to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere.

- 1.10. "Facility" has the meaning set forth in the Recitals.
- 1.11. "Generation Interconnection Agreement" means an agreement governing the interconnection of the Facility with PacifiCorp electric system.
- 1.12. "Generation Unit" means each separate electrical generator that contributes toward Nameplate Capacity Rating included in Exhibit A. For solar facilities, a generating unit is a complete solar electrical generation system within the Facility that is able to generate and deliver energy to the Point of Delivery independent of other Generation Units within the same Facility.
- 1.13. "Letter of Credit" means an engagement by a bank or other person made at the request of a customer that the issuer will honor drafts or other demands for payment upon compliance with the conditions specified in the letter of credit.
- 1.14. "Licensed Professional Engineer" or "LPE" means a person who is licensed to practice engineering in the state where the Facility is located, who has no economic relationship, association, or nexus with the Seller, and who is not a representative of a consulting engineer, contractor, designer or other individual involved in the development of the Facility, or of a manufacturer or supplier of any equipment installed in the Facility. Such Licensed Professional Engineer shall be licensed in an appropriate engineering discipline for the required certification being made and be acceptable to PGE in its reasonable judgment.
- 1.15. "Lost Energy" means "Lost Energy" means ((the Guarantee of Mechanical Availability as set forth in 3.1.10 / MAP) X Net Output for a Calendar Year) Net Output for the Calendar Year. Lost Energy shall be zero unless the result of the calculation in this subsection results in a positive number.
- 1.16. "Lost Energy Value" means Lost Energy X the excess of the annual time-weighted average Mid-C Index Price for On Peak Hours and Off Peak Hours over the time weighted average Contract Price for On Peak and Off Peak Hours for the corresponding time period (provided that such excess shall not exceed the Contract Price and further provided that Lost Energy is deemed to be zero prior to reaching the Commercial Operation Date) plus any reasonable costs incurred by PGE to purchase replacement power and/or transmission to deliver the replacement power to the Point of Delivery (For Start-Up Lost Energy Value See 1.35).
- 1.17. "Mechanical Availability Percentage" or "MAP" shall mean that percentage for any Contract Year for the Facility calculated in accordance with the following formula:

MAP = 100 X (Operational Hours) /(Base Hours X Number of Units)

1.18. "Mid-C Index Price" means the Day Ahead Intercontinental Exchange ("ICE") index price for the bilateral OTC market for energy at the Mid-C Physical for Average On Peak Power and Average Off Peak Power found on the following website:

Blue Marmot/201 Talbott/227 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

https://www.theice.com/products/OTC/Physical-Energy/Electricity. In the event ICE no longer publishes this index, PGE and the Seller agree to select an alternative successor index representative of the Mid-C trading hub.

- 1.19. "Nameplate Capacity Rating" means the maximum capacity of the Facility as stated by the manufacturer, expressed in kW, which shall not exceed 10,000 kW.
- 1.20. "Net Dependable Capacity" means the maximum capacity the Facility can sustain over a specified period modified for seasonal limitations, if any, and reduced by the capacity required for station service or auxiliaries.
- 1.21. "Net Output" means all energy expressed in kWhs produced by the Facility, less station and other onsite use and less transformation and transmission losses.
- 1.22. "Number of Units" means the number of Generation Units in the Facility as specified in Exhibit A.
 - 1.23. "Off-Peak Hours" has the meaning provided in the Schedule.
 - 1.24. "On-Peak Hours" has the meaning provided in the Schedule.
- 1.25. "Operational Hours" for the Facility means the total across all Generation Units of the number of hours each of the Facility's Generation Units are potentially capable of producing power at its Nameplate Capacity Rating regardless of actual weather conditions, season and the time of day or night, without any mechanical operating constraint or restriction, and potentially capable of delivering such power to the Point of Delivery in a Contract Year. During up to, but not more than, two hundred (200) hours of Planned Maintenance during a Contract Year for each Generation Unit and hours during which an event of Force Majeure exists, a Generation Unit shall be considered potentially capable of delivering such power to the Point of Delivery. For example, in the absence of any Planned Maintenance beyond 200 hours on any Generation Unit or Event of Force Majeure, the Operational Hours for a wind farm with five (5) separate two (2) MW turbines would be 43,800 for a Contract Year.
- 1.26. "Planned Maintenance" means outages scheduled ninety (90) days in advance, with PGE's prior written consent, which shall not be unreasonably withheld.
 - 1.27. "Point of Delivery" means the PGE system.
- 1.28. "Pre-Commercial Operation Date Minimum Net Output" shall mean, unless such MWh is specifically set forth by Seller in Exhibit A, an amount in MWh equal to seventy-five percent (75%) of Nameplate Capacity Rating X thirty percent (30%) for a wind or other renewable QF or fifty percent (50%) for a solar QF X (whole months since the date selected in Section 2.2.1 / 12) X (8760 hours 200 hours (assumed Planned Maintenance)) for each month. If Seller has provided specific expected monthly Net Output amounts for the Facility in Exhibit A, "Pre-Commercial Operation Date Minimum Net Output" shall mean seventy-five percent (75%) X expected net output set forth in Exhibit A for each month.

Blue Marmot/201 Talbott/228 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

- 1.29. "Prime Rate" means the publicly announced prime rate or reference rate for commercial loans to large businesses with the highest credit rating in the United States in effect from time to time quoted by Citibank, N.A. If a Citibank, N.A. prime rate is not available, the applicable Prime Rate shall be the announced prime rate or reference rate for commercial loans in effect from time to time quoted by a bank with \$10 billion or more in assets in New York City, N.Y., selected by the Party to whom interest based on the prime rate is being paid.
- 1.30. "Prudent Electrical Practices" means those practices, methods, standards and acts engaged in or approved by a significant portion of the electric power industry in the Western Electricity Coordinating Council that at the relevant time period, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with good business practices, reliability, economy, safety and expedition, and which practices, methods, standards and acts reflect due regard for operation and maintenance standards recommended by applicable equipment suppliers and manufacturers, operational limits, and all applicable laws and regulations. Prudent Electrical Practices are not intended to be limited to the optimum practice, method, standard or act to the exclusion of all others, but rather to those practices, methods and acts generally acceptable or approved by a significant portion of the electric power generation industry in the relevant region, during the relevant period, as described in the immediate preceding sentence.
- 1.31. "Required Facility Documents" means all licenses, permits, authorizations, and agreements necessary for construction, operation, interconnection, and maintenance of the Facility including without limitation those set forth in Exhibit B.
- 1.32. "RPS Attributes" means all attributes related to the Net Output generated by the Facility that are required in order to provide PGE with "qualifying electricity," as that term is defined in Oregon's Renewable Portfolio Standard Act, Ore. Rev. Stat. 469A.010, in effect at the time of execution of this Agreement. RPS Attributes do not include Environmental Attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity and not needed to ensure that there are zero net emissions associated with the generation of electricity.
- 1.33. "Schedule" shall mean PGE Schedule 201 filed with the Oregon Public Utilities Commission ("Commission") in effect on the Effective Date of this Agreement and attached hereto as Exhibit D, the terms of which are hereby incorporated by reference.
- 1.34. "Senior Lien" means a prior lien which has precedence as to the property under the lien over another lien or encumbrance
- 1.35. "Start-Up Lost Energy Value" means for the period after the date specified in Section 2.2.2 but prior to achievement of the Commercial Operation Date: zero, unless the Net Output is less than the pro-rated Pre-Commercial Operation Date Minimum Net Output for the applicable delay period, and the time-weighted average of the delay period's Mid-C Index Price for On-Peak Hours and Off-Peak Hours is greater

than the time-weighted average of the delay period's Contract Price for On-Peak Hours and Off-Peak Hours, in which case Startup Lost Energy Value equals: (pro-rated Pre-Commercial Operation Date Minimum Net Output for the applicable period - Net Output for the applicable period) X (the lower of: the time-weighted average of the Contract Price for On-Peak hours and Off-Peak Hours during the applicable period; or (the time-weighted average of the Mid-C Index Price for On-Peak Hours and Off-Peak Hours during the applicable period). The time-weighted average in this section will reflect the relative proportions of On-Peak Hours and Off-Peak Hours in each day.

- 1.36. "Start-Up Testing" means the completion of applicable required factory and start-up tests as set forth in Exhibit C.
- 1.37. "Step-in Rights" means the right of one party to assume an intervening position to satisfy all terms of an agreement in the event the other party fails to perform its obligations under the agreement.
- 1.38. "Term" shall mean the period beginning on the Effective Date and ending on the Termination Date.
- 1.39. "Test Period" shall mean a period of sixty (60) days or a commercially reasonable period determined by the Seller.
- 1.40. "Transmission Agreement" means an agreement executed by the Seller and the Transmission Provider(s) for Transmission Services.
- 1.41. "Transmission Curtailment" means a limitation on Seller's ability to deliver any portion of the scheduled energy to PGE due to the unavailability of transmission to the Point of Delivery (for any reason other than Force Majeure).
- 1.42. "Transmission Curtailment Replacement Energy Cost" means the greater of zero or the amount calculated as: ((Mid-C Index Price Contract Price) X curtailed energy) for periods of Transmission Curtailment.
- 1.43. "Transmission Provider(s)" means the signatory (other than the Seller) to the Transmission Agreement.
- 1.44. "Transmission Services" means any and all services (including but not limited to ancillary services and control area services) required for the firm transmission and delivery of Energy from the Facility to the Point of Delivery for a term not less than the Term of this Agreement.

References to Recitals, Sections, and Exhibits are to be the recitals, sections and exhibits of this Agreement.

SECTION 2: TERM; COMMERCIAL OPERATION DATE

2.1. This Agreement shall become effective upon execution by both Parties ("Effective Date").

- 2.2. Time is of the essence of this Agreement, and Seller's ability to meet certain requirements prior to the Commercial Operation Date and to complete all requirements to establish the Commercial Operation Date is critically important. Therefore,
 - 2.2.1. By March 1, 2020 Seller shall begin initial deliveries of Net Output; and
- 2.2.2. By March 31, 2020 Seller shall have completed all requirements under Section 1.5 and shall have established the Commercial Operation Date.
- 2.2.3. Unless the Parties agree in writing that a later Commercial Operation Date is reasonable and necessary, the Commercial Operation Date shall be no more than three (3) years from the Effective Date. PGE will not unreasonably withhold agreement to a Commercial Operation Date that is more than three (3) years from the Effective date if the Seller has demonstrated that a later Commercial Operation Date is reasonable and necessary.
- 2.3. This Agreement shall terminate on <u>date 18 years after effective date</u>, or the date the Agreement is terminated in accordance with Section 8 or 11, whichever is earlier ("Termination Date").

SECTION 3: REPRESENTATIONS AND WARRANTIES

- 3.1. Seller and PGE represent, covenant, and warrant as follows:
- 3.1.1. Seller warrants it is a <u>Limited liability company</u> duly organized under the laws of **Delaware**.
- 3.1.2. Seller warrants that the execution and delivery of this Agreement does not contravene any provision of, or constitute a default under, any indenture, mortgage, or other material agreement binding on Seller or any valid order of any court, or any regulatory agency or other body having authority to which Seller is subject.
- 3.1.3. Seller warrants that the Facility is and shall for the Term of this Agreement continue to be a "Qualifying Facility" ("QF") as that term is defined in the version of 18 C.F.R. Part 292 in effect on the Effective Date. Seller has provided the appropriate QF certification, which may include a Federal Energy Regulatory Commission ("FERC") self-certification to PGE prior to PGE's execution of this Agreement. At any time during the Term of this Agreement, PGE may require Seller to provide PGE with evidence satisfactory to PGE in its reasonable discretion that the Facility continues to qualify as a QF under all applicable requirements.
- 3.1.4. Seller warrants that it has not within the past two (2) years been the debtor in any bankruptcy proceeding, and Seller is and will continue to be for the Term of this Agreement current on all of its financial obligations.
- 3.1.5. Seller warrants that during the Term of this Agreement, all of Seller's right, title and interest in and to the Facility shall be free and clear of all liens and encumbrances other than liens and encumbrances arising from third-party financing of the Facility other than workers', mechanics', suppliers' or similar liens, or tax liens, in each case arising in the ordinary course of business that are either not yet due and

payable or that have been released by means of a performance bond acceptable to PGE posted within eight (8) calendar days of the commencement of any proceeding to foreclose the lien.

- 3.1.6. Seller warrants that it will design and operate the Facility consistent with Prudent Electrical Practices.
- 3.1.7. Seller warrants that the Facility has a Nameplate Capacity Rating not greater than 10,000 kW.
 - 3.1.8. Seller warrants that Net Dependable Capacity of the Facility is 10,000 kW.
- 3.1.9. Seller estimates that the average annual Net Output to be delivered by the Facility to PGE is 21,950,953 kilowatt-hours ("kWh"), which amount PGE will include in its resource planning.
- 3.1.10. Seller represents and warrants that the Facility shall achieve the following Mechanical Availability Percentages ("Guarantee of Mechanical Availability"):
- 3.1.10.1. Ninety percent (90%) beginning in the first Contract Year and extending through the Term for the Facility, if the Facility was operational and sold electricity to PGE or another buyer prior to the Effective Date of this Agreement; or
- 3.1.10.2. Ninety percent (90%) beginning in Contract Year three and extending throughout the remainder of the Term.
- 3.1.10.3. Annually, within 90 days of the end of each Contract Year, Seller shall send to PGE a detailed written report demonstrating and providing evidence of the actual MAP for the previous Contract Year.
- 3.1.10.4. Seller's failure to meet the Guarantee of Mechanical Availability in a Calendar Year shall result in damages payable to PGE by Seller equal to the Lost Energy Value. PGE shall bill Seller for such damages in accordance with Section 7.
- 3.1.11. Seller will deliver from the Facility to PGE at the Point of Delivery Net Output not to exceed a maximum of 33,750,000 kWh of Net Output during each Contract Year ("Maximum Net Output"). The cost of delivering energy from the Facility to PGE is the sole responsibility of the Seller.
- 3.1.12. By the Commercial Operation Date, Seller has entered into a Generation Interconnection Agreement for a term not less than the term of this Agreement.
- 3.1.13. PGE warrants that it has not within the past two (2) years been the debtor in any bankruptcy proceeding, and PGE is and will continue to be for the Term of this Agreement current on all of its financial obligations.
- 3.1.14. Seller warrants that the Facility satisfies the eligibility requirements specified in the Definition of a Small Cogeneration Facility or Small Power Production Facility Eligible to Receive the Standard Renewable Rates and Standard Renewable PPA in PGE's Schedule and Seller will not make any changes in its ownership, control or management during the term of this Agreement that would cause it to not be in compliance with the Definition of a Small Cogeneration Facility or Small Power

Blue Marmot/201 Talbott/232 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

Production Facility Eligible to Receive the Standard Renewable Rates and Standard Renewable PPA in PGE's Schedule. Seller will provide, upon request by PGE not more frequently than every 36 months, such documentation and information as may be reasonably required to establish Seller's continued compliance with such Definition. PGE agrees to take reasonable steps to maintain the confidentiality of any portion of the above described documentation and information that the Seller identifies as confidential except PGE will provide all such confidential information to the Commission upon the Commission's request.

3.1.15. Seller warrants that it will comply with all requirements necessary for all Transferred RECs (as defined in Section 4.5) associated with Net Output to be issued, monitored, accounted for, and transferred by and through the Western Renewable Energy Generation System consistent with the provisions of OAR 330-160-0005 through OAR 330-160-0050. PGE warrants that it will reasonably cooperate in Seller's efforts to meet such requirements, including, for example serving as the qualified reporting entity for the Facility if the Facility is located in PGE's balancing authority.

SECTION 4: DELIVERY OF POWER, PRICE AND ENVIRONMENTAL ATTRIBUTES

- 4.1. Commencing on the Effective Date and continuing through the Term of this Agreement, Seller shall sell to PGE the entire Net Output delivered from the Facility at the Point of Delivery.
 - 4.2. PGE shall pay Seller the Contract Price for all delivered Net Output.
- 4.3. Upon completion of construction of the Facility, Seller shall provide PGE an As-built Supplement to specify the actual Facility as built. Seller shall not increase the Nameplate Capacity Rating above that specified in Exhibit A or increase the ability of the Facility to deliver Net Output in quantities in excess of the Net Dependable Capacity, or the Maximum Net Output as described in Section 3.1.11 above, through any means including, but not limited to, replacement, modification, or addition of existing equipment, except with prior written notice to PGE. In the event Seller increases the Nameplate Capacity Rating of the Facility to no more than 10,000 kW pursuant to this section, PGE shall pay the Contract Price for the additional delivered Net Output. In the event Seller increases the Nameplate Capacity Rating to greater than 10,000 kW, then Seller shall be required to enter into a new power purchase agreement for all delivered Net Output proportionally related to the increase of Nameplate Capacity above 10,000 kW.
- 4.4. Seller shall provide preschedules for all deliveries of energy hereunder, including identification of receiving and generating control areas, by 9:00:00 PPT on the last business day prior to the scheduled date of delivery. All energy shall be scheduled according to the most current North America Energy Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) scheduling rules and practices. The Parties' respective representatives shall maintain hourly real-time schedule coordination; provided, however, that in the absence of such coordination, the hourly schedule established by the exchange of preschedules shall be considered final. Seller and PGE shall maintain records of hourly energy schedules for accounting and

Blue Marmot/201 Talbott/233 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

operating purposes. The final E-Tag shall be the controlling evidence of the Parties' schedule. All energy shall be prescheduled according to customary WECC scheduling practices. Seller shall make commercially reasonable efforts to schedule in any hour an amount equal to its expected Net Output for such hour. Seller shall maintain a minimum of two years records of Net Output and shall agree to allow PGE to have access to such records and to imbalance information kept by the Transmission Provider.

From the start of the Renewable Resource Deficiency Period through the remainder of the Term of this Agreement, Seller shall provide and PGE shall acquire the RPS Attributes for the Contract Years as specified in the Schedule and Seller shall retain ownership of all other Environmental Attributes (if any). During the Renewable Resource Sufficiency Period, Seller shall retain all Environmental Attributes in accordance with the Schedule. The Contract Price includes full payment for the Net Output and any RPS Attributes transferred to PGE under this Agreement. With respect to Environmental Attributes not transferred to PGE under this Agreement ("Seller-Retained Environmental Attributes") Seller may report under §1605(b) of the Energy Policy Act of 1992 or under any applicable program as belonging to Seller any of the Seller-Retained Environmental Attributes, and PGE shall not report under such program that such Seller-Retained Environmental Attributes belong to it. With respect to RPS Attributes transferred to PGE under this Agreement ("Transferred RECs"), PGE may report under §1605(b) of the Energy Policy Act of 1992 or under any applicable program as belonging to it any of the Transferred RECs, and Seller shall not report under such program that such Transferred RECs belong to it.

SECTION 5: OPERATION AND CONTROL

- 5.1. Seller shall operate and maintain the Facility in a safe manner in accordance with the Generation Interconnection Agreement, and Prudent Electrical Practices. PGE shall have no obligation to purchase Net Output from the Facility to the extent the interconnection of the Facility to PGE's electric system is disconnected, suspended or interrupted, in whole or in part, pursuant to the Generation Interconnection Agreement, or to the extent generation curtailment is required as a result of Seller's noncompliance with the Generation Interconnection Agreement. Seller is solely responsible for the operation and maintenance of the Facility. PGE shall not, by reason of its decision to inspect or not to inspect the Facility, or by any action or inaction taken with respect to any such inspection, assume or be held responsible for any liability or occurrence arising from the operation and maintenance by Seller of the Facility.
- 5.2. Seller agrees to provide sixty (60) days advance written notice of any scheduled maintenance that would require shut down of the Facility for any period of time.
- 5.3. If the Facility ceases operation for unscheduled maintenance, Seller immediately shall notify PGE of the necessity of such unscheduled maintenance, the time when such maintenance has occurred or will occur, and the anticipated duration of such maintenance. Seller shall take all reasonable measures and exercise its best

efforts to avoid unscheduled maintenance, to limit the duration of such unscheduled maintenance, and to perform unscheduled maintenance during Off-Peak hours.

SECTION 6: CREDITWORTHINESS

In the event Seller: a) is unable to represent or warrant as required by Section 3 that it has not been a debtor in any bankruptcy proceeding within the past two (2) years; b) becomes such a debtor during the Term; or c) is not or will not be current on all its financial obligations, Seller shall immediately notify PGE and shall promptly (and in no less than 10 days after notifying PGE) provide default security in an amount reasonably acceptable to PGE in one of the following forms: Senior Lien, Step-in Rights, a Cash Escrow or Letter of Credit. The amount of such default security that shall be acceptable to PGE shall be equal to: (annual On Peak Hours) X (On Peak Price – Off Peak Price) X (Net Dependable Capacity). Notwithstanding the foregoing, in the event Seller is not current on construction related financial obligations, Seller shall notify PGE of such delinquency and PGE may, in its discretion, grant an exception to the requirements to provide default security if the QF has negotiated financial arrangements with the construction loan lender that mitigate Seller's financial risk to PGE.

SECTION 7: BILLINGS, COMPUTATIONS AND PAYMENTS

- 7.1. On or before the thirtieth (30th) day following the end of each Billing Period, PGE shall send to Seller payment for Seller's deliveries of Net Output to PGE, together with computations supporting such payment. PGE may offset any such payment to reflect amounts owing from Seller to PGE pursuant to this Agreement and any other agreement related to the Facility between the Parties or otherwise. On or before the thirtieth (30th) day following the end of each Contract Year, PGE shall bill for any Lost Energy Value accrued pursuant to this Agreement.
- 7.2. Any amounts owing after the due date thereof shall bear interest at the Prime Rate plus two percent (2%) from the date due until paid; provided, however, that the interest rate shall at no time exceed the maximum rate allowed by applicable law.

SECTION 8: DEFAULT, REMEDIES AND TERMINATION

- 8.1. In addition to any other event that may constitute a default under this Agreement, the following events shall constitute defaults under this Agreement:
- 8.1.1. Breach by Seller or PGE of a representation or warranty, except for Section 3.1.4, set forth in this Agreement.
- 8.1.2. Seller's failure to provide default security, if required by Section 6, prior to delivery of any Net Output to PGE or within 10 days of notice.
- 8.1.3. Seller's failure to meet the Guarantee of Mechanical Availability established in Section 3.1.10 for two consecutive Contract Years or Seller's failure to provide any written report required by that section.
 - 8.1.4. If Seller is no longer a Qualifying Facility.
 - 8.1.5. Failure of PGE to make any required payment pursuant to Section 7.1.

- 8.1.6. Seller's failure to meet the Commercial Operation Date.
- 8.2. In the event of a default under Section 8.1.6, PGE may provide Seller with written notice of default. Seller shall have one year in which to cure the default during which time the Seller shall pay PGE damages equal to the Lost Energy Value. If Seller is unable to cure the default, PGE may immediately terminate this Agreement as provided in Section 8.3. PGE's resource sufficiency/deficiency position shall have no bearing on PGE's right to terminate the Agreement under this Section 8.2.
- 8.3. In the event of a default hereunder, except as otherwise provided in this Agreement, the non-defaulting party may immediately terminate this Agreement at its sole discretion by delivering written notice to the other Party. In addition, the non-defaulting Party may pursue any and all legal or equitable remedies provided by law or pursuant to this Agreement including damages related to the need to procure replacement power. A termination hereunder shall be effective upon the date of delivery of notice, as provided in Section 20. The rights provided in this Section 8 are cumulative such that the exercise of one or more rights shall not constitute a waiver of any other rights.
- 8.4. If this Agreement is terminated as provided in this Section 8, PGE shall make all payments, within thirty (30) days, that, pursuant to the terms of this Agreement, are owed to Seller as of the time of receipt of notice of default. PGE shall not be required to pay Seller for any Net Output delivered by Seller after such notice of default.
- 8.5. In the event PGE terminates this Agreement pursuant to this Section 8, and Seller wishes to again sell Net Output to PGE following such termination, PGE in its sole discretion may require that Seller shall do so subject to the terms of this Agreement, including but not limited to the Contract Price until the Term of this Agreement (as set forth in Section 2.3) would have run in due course had the Agreement remained in effect. At such time Seller and PGE agree to execute a written document ratifying the terms of this Agreement.
- 8.6. Sections 8.1, 8.4, 8.5, 10, and 19.2 shall survive termination of this Agreement.

SECTION 9: TRANSMISSION CURTAILMENTS

- 9.1. Seller shall give PGE notice as soon as reasonably practicable of any Transmission Curtailment that is likely to affect Seller's ability to deliver any portion of energy scheduled pursuant to Section 4.4 of this Agreement.
- 9.2. If as the result of a Transmission Curtailment, Seller does not deliver any portion of energy (including real-time adjustments), scheduled pursuant to Section 4.4 of this Agreement, Seller shall pay PGE the Transmission Curtailment Replacement Energy Cost for the number of MWh of energy reasonably determined by PGE as the difference between (i) the scheduled energy that would have been delivered to PGE under this Agreement during the period of Transmission Curtailment and (ii) the actual energy, if any, that was delivered to PGE for the period.

Blue Marmot/201 Talbott/236 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

SECTION 10: INDEMNIFICATION AND LIABILITY

- 10.1. Seller agrees to defend, indemnify and hold harmless PGE, its directors, officers, agents, and representatives against and from any and all loss, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with Seller's delivery of electric power to PGE or with the facilities at or prior to the Point of Delivery, or otherwise arising out of this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PGE, Seller or others, excepting to the extent such loss, claim, action or suit may be caused by the negligence of PGE, its directors, officers, employees, agents or representatives.
- 10.2. PGE agrees to defend, indemnify and hold harmless Seller, its directors, officers, agents, and representatives against and from any and all loss, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with PGE's receipt of electric power from Seller or with the facilities at or after the Point of Delivery, or otherwise arising out of this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PGE, Seller or others, excepting to the extent such loss, claim, action or suit may be caused by the negligence of Seller, its directors, officers, employees, agents or representatives.
- 10.3. Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a Party to this Agreement. No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or to the public, nor affect the status of PGE as an independent public utility corporation or Seller as an independent individual or entity.
- 10.4. NEITHER PARTY SHALL BE LIABLE TO THE OTHER FOR SPECIAL, PUNITIVE, INDIRECT OR CONSEQUENTIAL DAMAGES, WHETHER ARISING FROM CONTRACT, TORT (INCLUDING NEGLIGENCE), STRICT LIABILITY OR OTHERWISE.

SECTION 11: INSURANCE

11.1. Prior to the connection of the Facility to PGE's electric system, provided such Facility has a design capacity of 200 kW or more, Seller shall secure and continuously carry for the Term hereof, with an insurance company or companies rated not lower than "B+" by the A. M. Best Company, insurance policies for bodily injury and property damage liability. Such insurance shall include provisions or endorsements naming PGE, it directors, officers and employees as additional insureds; provisions that such insurance is primary insurance with respect to the interest of PGE and that any insurance or self-insurance maintained by PGE is excess and not contributory insurance with the insurance required hereunder; a cross-liability or severability of

Blue Marmot/201 Talbott/237 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

insurance interest clause; and provisions that such policies shall not be canceled or their limits of liability reduced without thirty (30) days' prior written notice to PGE. Initial limits of liability for all requirements under this section shall be \$1,000,000 million single limit, which limits may be required to be increased or decreased by PGE as PGE determines in its reasonable judgment economic conditions or claims experience may warrant.

- 11.2. Prior to the connection of the Facility to PGE's electric system, provided such facility has a design capacity of 200 kW or more, Seller shall secure and continuously carry for the Term hereof, in an insurance company or companies rated not lower than "B+" by the A. M. Best Company, insurance acceptable to PGE against property damage or destruction in an amount not less than the cost of replacement of the Facility. Seller promptly shall notify PGE of any loss or damage to the Facility. Unless the Parties agree otherwise, Seller shall repair or replace the damaged or destroyed Facility, or if the facility is destroyed or substantially destroyed, it may terminate this Agreement. Such termination shall be effective upon receipt by PGE of written notice from Seller. Seller shall waive its insurers' rights of subrogation against PGE regarding Facility property losses.
- 11.3. Prior to the connection of the Facility to PGE's electric system and at all other times such insurance policies are renewed or changed, Seller shall provide PGE with a copy of each insurance policy required under this Section, certified as a true copy by an authorized representative of the issuing insurance company or, at the discretion of PGE, in lieu thereof, a certificate in a form satisfactory to PGE certifying the issuance of such insurance. If Seller fails to provide PGE with copies of such currently effective insurance policies or certificates of insurance, PGE at its sole discretion and without limitation of other remedies, may upon ten (10) days advance written notice by certified or registered mail to Seller either withhold payments due Seller until PGE has received such documents, or purchase the satisfactory insurance and offset the cost of obtaining such insurance from subsequent power purchase payments under this Agreement.

SECTION 12: FORCE MAJEURE

12.1. As used in this Agreement, "Force Majeure" or "an event of Force Majeure" means any cause beyond the reasonable control of the Seller or of PGE which, despite the exercise of due diligence, such Party is unable to prevent or overcome. By way of example, Force Majeure may include but is not limited to acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes, and other labor disturbances, earthquakes, fires, lightning, epidemics, sabotage, restraint by court order or other delay or failure in the performance as a result of any action or inaction on behalf of a public authority which by the exercise of reasonable foresight such Party could not reasonably have been expected to avoid and by the exercise of due diligence, it shall be unable to overcome, subject, in each case, to the requirements of the first sentence of this paragraph. Force Majeure, however, specifically excludes the cost or availability of resources to operate the Facility, changes in market conditions that affect

Blue Marmot/201 Talbott/238 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

the price of energy or transmission, wind or water droughts, and obligations for the payment of money when due.

- 12.2. If either Party is rendered wholly or in part unable to perform its obligation under this Agreement because of an event of Force Majeure, that Party shall be excused from whatever performance is affected by the event of Force Majeure to the extent and for the duration of the Force Majeure, after which such Party shall recommence performance of such obligation, provided that:
- 12.2.1. the non-performing Party, shall, promptly, but in any case within one (1) week after the occurrence of the Force Majeure, give the other Party written notice describing the particulars of the occurrence; and
- 12.2.2. the suspension of performance shall be of no greater scope and of no longer duration than is required by the Force Majeure; and
- 12.2.3. the non-performing Party uses its best efforts to remedy its inability to perform its obligations under this Agreement.
- 12.3. No obligations of either Party which arose before the Force Majeure causing the suspension of performance shall be excused as a result of the Force Majeure.
- 12.4. Neither Party shall be required to settle any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to the Party's best interests.

SECTION 13: SEVERAL OBLIGATIONS

Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership or joint venture or to impose a trust or partnership duty, obligation or liability between the Parties. If Seller includes two or more parties, each such party shall be jointly and severally liable for Seller's obligations under this Agreement.

SECTION 14: CHOICE OF LAW

This Agreement shall be interpreted and enforced in accordance with the laws of the state of Oregon, excluding any choice of law rules which may direct the application of the laws of another jurisdiction.

SECTION 15: PARTIAL INVALIDITY AND PURPA REPEAL

It is not the intention of the Parties to violate any laws governing the subject matter of this Agreement. If any of the terms of the Agreement are finally held or determined to be invalid, illegal or void as being contrary to any applicable law or public policy, all other terms of the Agreement shall remain in effect. If any terms are finally held or determined to be invalid, illegal or void, the Parties shall enter into negotiations concerning the terms affected by such decision for the purpose of achieving conformity with requirements of any applicable law and the intent of the Parties to this Agreement.

Blue Marmot/201 Talbott/239 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

In the event the Public Utility Regulatory Policies Act (PURPA) is repealed, this Agreement shall not terminate prior to the Termination Date, unless such termination is mandated by state or federal law.

SECTION 16: WAIVER

Any waiver at any time by either Party of its rights with respect to a default under this Agreement or with respect to any other matters arising in connection with this Agreement must be in writing, and such waiver shall not be deemed a waiver with respect to any subsequent default or other matter.

SECTION 17: GOVERNMENTAL JURISDICTION AND AUTHORIZATIONS

This Agreement is subject to the jurisdiction of those governmental agencies having control over either Party or this Agreement. Seller shall at all times maintain in effect all local, state and federal licenses, permits and other approvals as then may be required by law for the construction, operation and maintenance of the Facility, and shall provide upon request copies of the same to PGE.

SECTION 18: SUCCESSORS AND ASSIGNS

This Agreement and all of the terms hereof shall be binding upon and inure to the benefit of the respective successors and assigns of the Parties. No assignment hereof by either Party shall become effective without the written consent of the other Party being first obtained and such consent shall not be unreasonably withheld. Notwithstanding the foregoing, either Party may assign this Agreement without the other Party's consent as part of (a) a sale of all or substantially all of the assigning Party's assets, or (b) a merger, consolidation or other reorganization of the assigning Party.

SECTION 19: ENTIRE AGREEMENT

- 19.1. This Agreement supersedes all prior agreements, proposals, representations, negotiations, discussions or letters, whether oral or in writing, regarding PGE's purchase of Net Output from the Facility. No modification of this Agreement shall be effective unless it is in writing and signed by both Parties.
- 19.2. By executing this Agreement, Seller releases PGE from any third party claims related to the Facility, known or unknown, which may have arisen prior to the Effective Date.

SECTION 20: NOTICES

20.1. All notices except as otherwise provided in this Agreement shall be in writing, shall be directed as follows and shall be considered delivered if delivered in person or when deposited in the U.S. Mail, postage prepaid by certified or registered mail and return receipt requested:

Blue Marmot/201 Talbott/240 Schedule 201

Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

	To Seller:	Blue Marmot VIII LLC c/o EDP Renewables North America LLC; Attention: General Counsel 808 Travis, Suite 700 Houston, Texas 77002
	with a copy to:	
	To PGE:	Contracts Manager QF Contracts, 3WTC0306 PGE - 121 SW Salmon St. Portland, Oregon 97204
or the		may change the person to whom such notices are addressed, oviding written notices thereof in accordance with this Section
execu		REOF, the Parties hereto have caused this Agreement to be re names as of the Effective Date.
PGE		
Name Title:	:	
_	Marmot VIII LLC e Seller)	
Name Title:	9:	

Blue Marmot/201 Talbott/241 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

EXHIBIT A DESCRIPTION OF SELLER'S FACILITY

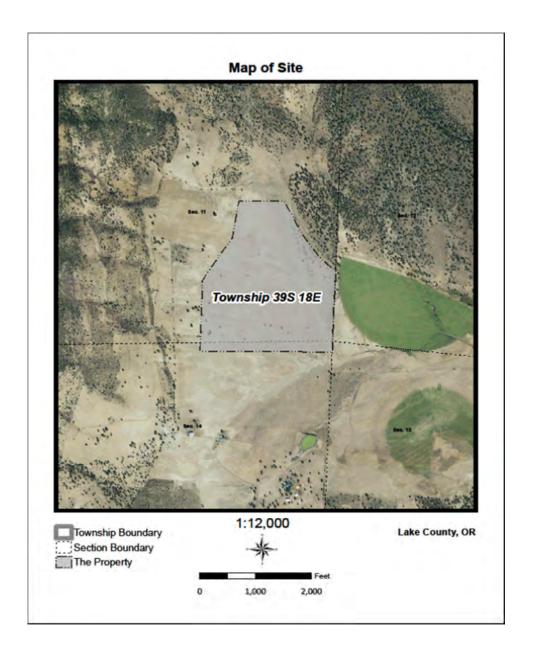
The facility will be a solar PV plant consisting of 39,324 polycrystalline modules of nominal 335W rating each. Total plant rating will be 13.174MWdc/10MWac. Modules will be mounted to single-axis trackers.

Central inverter stations will be located at intermediate points in the PV field. Modules will be evenly distributed to the inverter stations. The total inverter nameplate rating will be 10.0MWac. Each inverter will be directly coupled to a 34.5kV step-up transformer. The transformers will be connected to a 34.5kV AC collection system, which will feed into the plant switchgear.

The plant switchgear will feed a 34.5kV transmission line, which will run overhead approximately 11.1 miles to the PacifiCorp Mile-Hi Substation.

Inside the Mile-Hi Substation, the transmission line will connect to a new bay containing a facility-owned 34.5kV/115kV GSU transformer, associated breakers, switching, bus, and controls.

The facility-owned components at Mile-Hi substation are considered part of the self-certified qualifying facility.



Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

Solar Facility Characteristics:	Note this information is considered representative design information which is to be updated at the time of project construction and is subject to design finalization
1. Generation	22 accom and to subject to design manifestion
a. PVSyst (or equivalent) simulation results detail, including but not limited to:	
i. Annual MWh (AC) for the first calendar year of commercial operation	23,931
ii. Annual degradation factor	0.50%
iii. Average 24-hr profile of generation MWh (AC) for each month during the first calendar	See tab "Generation"
iv. Expected Solar Capacity Factor	27%
v. Maximum annual output (monthly MWh detail)	See tab "Generation"
iv. Loss Diagram	See tab "Generation"
2. Description of Modules:	
a. Module type	Polycrystalline Silicon
b. # of modules	39, 324
c. Max power voltage	37.4V
d. Max power current	8.97A
e. Max system voltage	1500V
f. Total DC system size	13,174kW
· · · · · · · · · · · · · · · · · · ·	13,174600
3. Description of Racking	
a. Racking	
i. Type: (fixed tilt, single-axis tracking, or dual-axis tracking, etc.)	Single-Axis Tracking
ii. Tilt angle (if fixed-tilt)	N/A
iii. Azimuth (default = south-facing)	South-Facing
4. Description of Inverters:	
a. Number of Inverters	5
b. Model	ABB PVS980-58-1818kVA-6
c. Maximum Power (kW)	2910kW DC
d. Operating Voltage (VAC)	600
e. Max. Output Current (A)	1925A
f. Rated DC Voltage	1500
g. Rated DC current	1945
h. Maximum Output (kW)	2000
	10.0MW
g. Facility AC Capacity Rating	
h. Inverter loading ratio	1.317
i. Facility AC rating	10.0MW
5. Description of transformers	
Inverter LV-MV	
a. # of transformers	5
b. Model	ABB PadPlus+
c. High Voltage Rating	34,500
d. Low Voltage Rating	600
e. MVA rating	2.0 each, 10.0 total
f. High voltage connection	Wye-Ground
g. Low voltage connection	Wye
GSU MV-HV	•
a. # of transformers	1
b. Model	ABB 10MVA
c. High Voltage Rating	115,000
d. Low Voltage Rating	34,500
e. MVA rating	10/12.5 ONAF
f. High voltage connection	Wye
g. Low voltage connection	Delta
	Meter shall be revenue-grade, located at POI. POI shall be slack bus
	on the high-side bushing of plant GSU transformer at Mile Hi
	Substation. Revenue meter shall transmit real-time data pulses
	(instantaneous MW, MVAR, KWH) to Operator's billing data
	program. Customer's 35kV switchgear at Mile Hi shall be fitted with
	Customer meter as an alternate data source. Breakers and relays
	at Customer's PV plant shall connect to operator SCADA system at
6. Description of metering, communications, and monitoring	Mile Hi substation via OPGW run on proposed Customer
	transmission line. Customer shall install line-protection panel,
	metering equipment and accessories, communication battery
	system, fiber optic network device and SCADA RTU (Remote
	Terminal Unit) in existing Mile Hi relay/control building to control,
	monitor, and transmit data to Operator and back to PV plant
	SCADA.
	15KVA, 240/120V 1-phase service at PV plant substation for
7. Description of stables are described as a second	Relay/SCADA/O&M building and plant accessory loads. 5KVA,
7. Description of station service requirements	240/120V 1-phase at Mile Hi substation for Customer controls
	equipment.
	equipment.
20	Transmission line shall be new radial line consisting of 34.5KV
20	ACSR, 1-conductor per phase with OPGW on wood poles, approx.
	11.1 miles. Line will originate at PV plant 34.5kV main switchgear
	and terminate at dead-end structure feeding a new 35kV breaker
	at Mile Hi Substation. 35kV breaker will feed new GSU and new
8. Description and timeline of interconnection and transmission plan	115KV breaker at Mile Hi Substation. POI shall be slack bus
o. Description and afficience of interconnection and transmission plan	225. Canci de ivile i il Sabstationi. I Oi silali de sidek dus

Blue Marmot/201 Talbott/244 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

EXHIBIT B REQUIRED FACILITY DOCUMENTS

Sellers Generation Interconnection Agreement

Transmission Service Agreement with PacifiCorp

Lease agreement

Conditional Use Permit issued by Lake County

Any additional permits that might be required by Lake County or Oregon Department of Environmental Quality, including access permit, building and electric permits, and storm water prevention permit

FERC Qualifying Facility self-certification

Blue Marmot/201 Talbott/245 Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

EXHIBIT C START-UP TESTING

VISUAL AN	D MECHANICAL	INSPECTIONS
-----------	--------------	-------------

INVERTER COMMISSIONING

ELECTRICAL OPERATION TESTS

SYSTEM MONITORING VERIFICATION

TRACKER VERIFICATION

INFRARED SCANS

BLOCK TESTING

72-HOUR FUNCTIONAL TEST

GRID MATCH TEST

POWER CHARACTERIZATION

REVENUE METER VERIFICATION

REACTIVE POWER TEST

POWER OUTPUT TEST - PLANT PERFORMANCE AND ACCEPTANCE

 $Blue\ Marmot/201$ Talbott/246 $Schedule\ 201$ $Standard\ Renewable\ Off-System\ Variable\ Power\ Purchase\ Agreement$ $Form\ Effective\ August\ 12,\ 2016$

EXHIBIT D SCHEDULE

SCHEDULE 201 QUALIFYING FACILITY 10 MW or LESS AVOIDED COST POWER PURCHASE INFORMATION

PURPOSE

To provide information about Standard Avoided Costs and Renewable Avoided Costs, Standard Power Purchase Agreements (PPA) and Negotiated PPAs, power purchase prices and price options for power delivered by a Qualifying Facility (QF) to the Company with nameplate capacity of 10,000 kW (10MW) or less.

AVAILABLE

To owners of QFs making sales of electricity to the Company in the State of Oregon (Seller).

APPLICABLE

For power purchased from small power production or cogeneration facilities that are QFs as defined in 18 Code of Federal Regulations (CFR) Section 292, that meet the eligibility requirements described herein and where the energy is delivered to the Company's system and made available for Company purchase pursuant to a Standard PPA.

ESTABLISHING CREDITWORTHINESS

The Seller must establish creditworthiness prior to service under this schedule. For a Standard PPA, a Seller may establish creditworthiness with a written acknowledgment that it is current on all existing debt obligations and that it was not a debtor in a bankruptcy proceeding within the preceding 24 months. If the Seller is not able to establish creditworthiness, the Seller must provide security deemed sufficient by the Company as set forth in the Standard PPA.

POWER PURCHASE INFORMATION

A Seller may call the Power Production Coordinator at (503) 464-8000 to obtain more information about being a Seller or how to apply for service under this schedule.

PPA

In accordance with terms set forth in this schedule and the Commission's Rules as applicable, the Company will purchase any Energy in excess of station service (power necessary to produce generation) and amounts attributable to conversion losses, which are made available from the Seller.

A Seller must execute a PPA with the Company prior to delivery of power to the Company. The agreement will have a term of up to 20 years as selected by the QF.

A QF with a nameplate capacity rating of 10 MW or less as defined herein may elect the option of a Standard PPA.

PPA (Continued)

Any Seller may elect to negotiate a PPA with the Company. Such negotiation will comply with the requirements of the Federal Energy Regulatory Commission (FERC), and the Commission including the guidelines in Order No. 07-360, and Schedule 202. Negotiations for power purchase pricing will be based on either the filed Standard Avoided Costs or Renewable Avoided Costs in effect at that time.

STANDARD PPA (Nameplate capacity of 10 MW or less)

A Seller choosing a Standard PPA will complete all informational and price option selection requirements in the applicable Standard PPA and submit the executed Agreement to the Company prior to service under this schedule. The Standard PPA is available at www.portlandgeneral.com. The available Standard PPAs are:

- Standard In-System Non-Variable Power Purchase Agreement
- Standard Off-System Non-Variable Power Purchase Agreement
- Standard In-System Variable Power Purchase Agreement
- Standard Off-System Variable Power Purchase Agreement
- Standard Renewable In-System Non-Variable Power Purchase Agreement
- Standard Renewable Off-System Non-Variable Power Purchase Agreement
- Standard Renewable In-System Variable Power Purchase Agreement
- Standard Renewable Off-System Variable Power Purchase Agreement

The Standard PPAs applicable to variable resources are available only to QFs utilizing wind, solar or run of river hydro as the primary motive force.

GUIDELINES FOR 10 MW OR LESS FACILITIES ELECTING STANDARD PPA

To execute the Standard PPA the Seller must complete all of the general project information requested in the applicable Standard PPA.

When all information required in the Standard PPA has been received in writing from the Seller, the Company will respond within 15 business days with a draft Standard PPA.

The Seller may request in writing that the Company prepare a final draft Standard PPA. The Company will respond to this request within 15 business days. In connection with such request, the QF must provide the Company with any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft Standard PPA.

When both parties are in full agreement as to all terms and conditions of the draft Standard PPA, the Company will prepare and forward to the Seller a final executable version of the agreement within 15 business days. Following the Company's execution, an executed copy will be returned to the Seller. Prices and other terms and conditions in the PPA will not be final and binding until the Standard PPA has been executed by both parties.

OFF-SYSTEM PPA

A Seller with a facility that interconnects with an electric system other than the Company's electric system may enter into a PPA with the Company after following the applicable Standard or Negotiated PPA guidelines and making the arrangements necessary for transmission of power to the Company's system.

BASIS FOR POWER PURCHASE PRICE

AVOIDED COST SUMMARY

The power purchase prices are based on either the Company's Standard Avoided Costs or Renewable Avoided Costs in effect at the time the agreement is executed. Avoided Costs are defined in 18 CFR 292.101(6) as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."

Monthly On-Peak prices are included in both the Standard Avoided Costs as listed in Tables 1a, 2a, and 3a and Renewable Avoided Costs as listed in Tables 4a, 5a, and 6a. Monthly Off-Peak prices are included in both the Standard Avoided Costs as listed in Tables 1b, 2b, and 3b and Renewable Avoided Costs as listed in Tables 4b, 5b, and 6b.

ON-PEAK PERIOD

The On-Peak period is 6:00 a.m. until 10:00 p.m., Monday through Saturday.

OFF-PEAK PERIOD

The Off-Peak period is 10:00 p.m. until 6:00 a.m., Monday through Saturday, and all day on Sunday.

Standard Avoided Costs are based on forward market price estimates through the Resource Sufficiency Period, the period of time during which the Company's Standard Avoided Costs are associated with incremental purchases of Energy and capacity from the market. For the Resource Deficiency Period, the Standard Avoided Costs reflect the fully allocated costs of a natural gas fueled combined cycle combustion turbine (CCCT) including fuel and capital costs. The CCCT Avoided Costs are based on the variable cost of Energy plus capitalized Energy costs at a 93% capacity factor based on a natural gas price forecast, with prices modified for shrinkage and transportation costs.

Renewable Avoided Costs are based on forward market price estimates through the Renewable Resource Sufficiency Period, the period of time during which the Company's Renewable Avoided Costs are associated with incremental purchases of energy and capacity from the market. For the Renewable Resource Deficiency Period, the Renewable Avoided Costs reflect the fully allocated costs of a wind plant including capital costs.

PRICING FOR STANDARD PPA

Pricing represents the purchase price per MWh the Company will pay for electricity delivered to a Point of Delivery (POD) within the Company's service territory pursuant to a Standard PPA up to the nameplate rating of the QF in any hour. Any Energy delivered in excess of the nameplate rating will be purchased at the applicable Off-Peak Prices for the selected pricing option.

The Standard PPA pricing will be based on either the Standard or Renewable Avoided Costs in effect at the time the agreement is executed.

The Company will pay the Seller either the Off-Peak Standard Avoided Cost pursuant to Tables 1b, 2b, or 3b or the Off-Peak Renewable Avoided Costs pursuant to Tables 4b, 5b, or 6b for: (a) all Net Output delivered prior to the Commercial Operation Date; (b) all Net Output deliveries greater than Maximum Net Output in any PPA year; (c) any generation subject to and as adjusted by the provisions of Section 4.3 of the Standard PPA; (d) Net Output delivered in the Off-Peak Period; and (e) deliveries above the nameplate capacity in any hour. The Company will pay the Seller either the On-Peak Standard Avoided Cost pursuant to Tables 1a, 2a, or 3a or the On-Peak Renewable Avoided Costs pursuant to Tables 4a, 5a, or 6a for all other Net Output. (See the PPA for defined terms.)

1) Standard Fixed Price Option

The Standard Fixed Price Option is based on Standard Avoided Costs including forecasted natural gas prices. It is available to all QFs.

This option is available for a maximum term of 15 years. Prices will be as established at the time the Standard PPA is executed and will be equal to the Standard Avoided Costs in Tables 1a and 1b, 2a and 2b, or 3a and 3c, depending on the type of QF, effective at execution. QFs using any resource type other than wind and solar are assumed to be Base Load QFs.

Prices paid to the Seller under the Standard Fixed Price Option include adjustments for the capacity contribution of the QF resource type relative to that of the avoided proxy resource. Both the Base Load QF resources (Tables 1a and 1b) and the avoided proxy resource, the basis used to determine Standard Avoided Costs for the Standard Fixed Price Option, are assumed to have a capacity contribution to peak of 100%. The capacity contribution for Wind QF resources (Tables 2a and 2b) is assumed to be 5%. The capacity contribution for Solar QF resources (Tables 3a and 3b) is assumed to be 5%.

Prices paid to the Seller under the Standard Fixed Price Option for Wind QFs (Tables 2a and 2b) include a reduction for the wind integration costs in Table 7. However, if the Wind QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the wind integration charges in Table 7, in addition to the prices listed in Tables 2a and 2b, for a net-zero effect.

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

Sellers with PPAs exceeding 15 years will receive pricing equal to the Mid-C Index Price for all years up to five in excess of the initial 15.

	TABLE 1a												
						ided Cos	ts						
			St	andard F	ixed Pric	e Option	for Base	Load QF	•				
				0	n-Peak F	orecast ((\$/MWH)						
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2016	28.21	22.46	15.61	14.71	12.46	16.96	23.96	26.96	24.96	23.71	26.71	31.46	
2017	29.96	28.21	24.71	20.96	19.46	20.46	27.96	30.96	29.46	27.71	28.71	33.71	
2018	31.71	31.11	28.11	22.13	21.28	21.28	29.93	33.37	30.63	28.61	31.86	35.71	
2019	33.94	31.95	27.97	23.70	22.00	23.13	31.67	35.08	33.37	31.38	32.52	38.21	
2020	35.74	33.64	29.45	24.95	23.15	24.35	33.34	36.94	35.14	33.04	34.24	40.24	
2021	67.43	67.34	65.41	64.69	64.41	64.50	64.61	64.73	64.84	65.48	68.60	68.72	
2022	69.01	68.84	68.08	67.13	66.81	66.91	67.04	67.17	67.29	67.83	71.38	71.70	
2023	71.95	71.76	70.39	69.19	69.07	69.18	69.31	69.45	69.58	70.12	73.56	73.70	
2024	74.17	73.85	72.67	71.29	71.10	71.21	71.35	71.50	71.63	72.20	76.49	76.64	
2025	77.19	77.30	75.84	74.88	75.02	75.14	75.30	75.47	75.62	75.80	82.57	82.89	
2026	85.18	85.30	82.77	81.28	81.22	81.36	81.56	81.74	81.90	82.36	89.02	88.72	
2027	86.85	86.76	85.14	83.12	82.89	83.03	83.00	83.32	83.46	83.97	91.39	91.15	
2028	89.32	89.31	87.96	85.46	85.30	85.46	85.31	85.64	85.95	86.65	94.66	93.55	
2029	94.06	93.99	91.23	88.74	87.97	88.15	87.71	88.06	88.61	89.34	98.37	98.11	
2030	97.60	97.54	94.87	92.62	92.40	92.57	92.61	93.00	93.12	93.68	102.42	102.70	
2031	99.56	99.50	96.78	94.48	94.26	94.43	94.47	94.87	94.99	95.56	104.47	104.76	
2032	103.85	103.80	100.57	98.18	97.96	98.15	98.23	98.65	98.76	99.36	108.86	109.41	
2033	106.56	106.51	103.17	100.72	100.50	100.69	100.78	101.21	101.32	101.93	111.67	112.26	
2034	109.12	109.07	105.60	103.10	102.88	103.08	103.17	103.61	103.72	104.35	114.33	114.96	
2035	111.55	111.51	107.91	105.35	105.12	105.33	105.43	105.89	105.99	106.63	116.87	117.54	
2036	113.85	113.80	110.14	107.53	107.30	107.51	107.60	108.07	108.18	108.83	119.27	119.95	
2037	116.50	116.45	112.72	110.06	109.82	110.04	110.14	110.61	110.73	111.39	122.03	122.73	
2038	119.08	119.03	115.22	112.51	112.27	112.49	112.59	113.08	113.19	113.87	124.71	125.42	
2039	121.47	121.42	117.54	114.77	114.53	114.75	114.85	115.35	115.47	116.15	127.21	127.93	
2040	124.25	124.20	120.25	117.43	117.18	117.41	117.51	118.02	118.14	118.84	130.10	130.85	
2041	126.72	126.67	122.64	119.76	119.51	119.74	119.85	120.36	120.49	121.20	132.68	133.44	

					TA	ABLE 1b						
						ded Cos	ts					
			Sta	andard Fi	xed Price	e Option	for Base	Load QF				
				0	ff-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	25.61	20.71	13.96	11.41	6.31	10.11	15.71	20.96	20.96	21.21	23.46	26.71
2017	25.71	24.21	22.21	15.71	13.71	12.71	19.71	25.21	25.46	24.71	25.71	27.96
2018	26.17	28.12	25.56	19.46	14.68	12.54	19.71	27.04	26.93	25.35	28.20	30.62
2019	29.84	28.09	25.75	18.15	15.81	14.64	22.83	29.26	29.55	28.67	29.84	32.47
2020	31.75	29.88	27.38	19.28	16.79	15.54	24.27	31.12	31.43	30.50	31.75	34.55
2021	28.88	28.79	26.86	26.15	25.87	25.95	26.07	26.19	26.30	26.94	30.06	30.18
2022	29.73	29.56	28.79	27.85	27.53	27.63	27.75	27.88	28.00	28.54	32.09	32.42
2023	31.78	31.59	30.21	29.01	28.90	29.00	29.14	29.27	29.40	29.95	33.38	33.52
2024	33.48	33.16	31.98	30.60	30.41	30.52	30.66	30.81	30.95	31.51	35.80	35.96
2025	35.58	35.69	34.24	33.27	33.42	33.53	33.70	33.86	34.01	34.19	40.97	41.28
2026	42.77	42.89	40.36	38.87	38.81	38.95	39.15	39.34	39.50	39.95	46.62	46.31
2027	43.63	43.54	41.91	39.89	39.66	39.80	39.77	40.09	40.24	40.74	48.16	47.92
2028	45.26	45.25	43.90	41.40	41.23	41.40	41.25	41.58	41.89	42.59	50.60	49.48
2029	49.15	49.08	46.32	43.83	43.06	43.24	42.80	43.15	43.70	44.43	53.46	53.20
2030	51.82	51.76	49.09	46.84	46.62	46.79	46.83	47.22	47.34	47.90	56.64	56.92
2031	52.90	52.84	50.11	47.82	47.59	47.77	47.81	48.21	48.33	48.90	57.81	58.10
2032	56.59	56.54	53.31	50.92	50.70	50.89	50.97	51.39	51.50	52.10	61.60	62.15
2033	58.08	58.03	54.69	52.24	52.02	52.21	52.30	52.73	52.84	53.45	63.19	63.78
2034	59.54	59.50	56.03	53.52	53.30	53.50	53.59	54.04	54.15	54.77	64.76	65.39
2035	61.18	61.14	57.54	54.98	54.75	54.96	55.06	55.52	55.62	56.26	66.50	67.17
2036	62.67	62.62	58.96	56.35	56.12	56.33	56.43	56.89	57.00	57.65	68.09	68.78
2037	64.17	64.12	60.39	57.73	57.49	57.71	57.80	58.28	58.39	59.06	69.69	70.39
2038	65.73	65.69	61.88	59.17	58.93	59.15	59.25	59.73	59.85	60.52	71.37	72.08
2039	67.09	67.04	63.16	60.40	60.15	60.38	60.48	60.98	61.09	61.78	72.83	73.56
2040	68.83	68.78	64.83	62.01	61.76	61.99	62.09	62.60	62.72	63.42	74.68	75.42
2041	70.23	70.17	66.14	63.27	63.02	63.25	63.36	63.87	63.99	64.71	76.19	76.95

					T/	ABLE 2a						
					Avoi	ded Cos	ts					
				Standard	I Fixed P	rice Optic	on for Wi	ind QF				
				0	n-Peak F	orecast (\$/MWH)				-	
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	24.37	18.62	11.77	10.87	8.62	13.12	20.12	23.12	21.12	19.87	22.87	27.62
2017	26.05	24.30	20.80	17.05	15.55	16.55	24.05	27.05	25.55	23.80	24.80	29.80
2018	27.72	27.12	24.12	18.14	17.29	17.29	25.94	29.38	26.64	24.62	27.87	31.72
2019	29.87	27.88	23.90	19.63	17.93	19.06	27.60	31.01	29.30	27.31	28.45	34.14
2020	31.59	29.49	25.30	20.80	19.00	20.20	29.19	32.79	30.99	28.89	30.09	36.09
2021	30.68	30.59	28.66	27.94	27.66	27.75	27.87	27.99	28.10	28.74	31.86	31.98
2022	31.56	31.39	30.62	29.68	29.36	29.46	29.59	29.72	29.84	30.38	33.93	34.25
2023	33.67	33.48	32.11	30.91	30.79	30.90	31.03	31.17	31.30	31.84	35.28	35.42
2024	35.38	35.06	33.88	32.49	32.30	32.42	32.56	32.70	32.84	33.40	37.70	37.85
2025	37.53	37.64	36.18	35.22	35.36	35.48	35.64	35.81	35.96	36.14	42.91	43.23
2026	44.75	44.87	42.35	40.86	40.79	40.94	41.13	41.32	41.48	41.94	48.60	48.29
2027	45.65	45.56	43.93	41.91	41.68	41.82	41.79	42.12	42.26	42.76	50.18	49.94
2028	47.32	47.31	45.96	43.46	43.30	43.46	43.31	43.64	43.95	44.65	52.66	51.55
2029	51.25	51.18	48.43	45.94	45.16	45.34	44.90	45.25	45.80	46.53	55.57	55.30
2030	53.96	53.90	51.23	48.98	48.76	48.93	48.97	49.36	49.48	50.04	58.78	59.06
2031	55.08	55.02	52.29	50.00	49.77	49.95	49.99	50.38	50.51	51.08	59.99	60.28
2032	58.77	58.72	55.49	53.10	52.88	53.07	53.15	53.57	53.68	54.28	63.78	64.33
2033	60.35	60.30	56.96	54.51	54.29	54.49	54.57	55.00	55.11	55.72	65.46	66.05
2034	61.88	61.83	58.36	55.86	55.63	55.84	55.93	56.37	56.48	57.10	67.09	67.72
2035	63.54	63.49	59.90	57.34	57.11	57.32	57.42	57.87	57.98	58.62	68.86	69.53
2036	65.04	65.00	61.33	58.72	58.49	58.70	58.80	59.27	59.38	60.03	70.46	71.15
2037	66.61	66.57	62.83	60.17	59.93	60.15	60.25	60.73	60.84	61.50	72.14	72.84
2038	68.23	68.18	64.37	61.66	61.42	61.64	61.74	62.23	62.34	63.02	73.86	74.57
2039	69.64	69.59	65.71	62.94	62.70	62.92	63.03	63.52	63.64	64.33	75.38	76.11
2040	71.42	71.37	67.41	64.60	64.35	64.58	64.68	65.18	65.30	66.00	77.27	78.01
2041	72.87	72.82	68.79	65.92	65.66	65.90	66.00	66.52	66.64	67.35	78.84	79.59

					T	ABLE 2b						
					Avo	ded Cos	ts					
				Standard	d Fixed P	rice Option	on for Wi	ind QF				
				0	ff-Peak F	orecast (\$/MWH)					
	_					_		_	_			
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	21.77	16.87	10.12	7.57	2.47	6.27	11.87	17.12	17.12	17.37	19.62	22.87
2017	21.80	20.30	18.30	11.80	9.80	8.80	15.80	21.30	21.55	20.80	21.80	24.05
2018	22.18	24.13	21.57	15.47	10.69	8.55	15.72	23.05	22.94	21.36	24.21	26.63
2019	25.77	24.02	21.68	14.08	11.74	10.57	18.76	25.19	25.48	24.60	25.77	28.40
2020	27.60	25.73	23.23	15.13	12.64	11.39	20.12	26.97	27.28	26.35	27.60	30.40
2021	24.65	24.56	22.63	21.92	21.64	21.72	21.84	21.96	22.07	22.71	25.83	25.95
2022	25.42	25.25	24.48	23.54	23.22	23.32	23.44	23.57	23.69	24.23	27.78	28.11
2023	27.39	27.20	25.82	24.62	24.51	24.61	24.75	24.88	25.01	25.56	28.99	29.13
2024	29.01	28.69	27.51	26.13	25.94	26.05	26.19	26.34	26.48	27.04	31.33	31.49
2025	31.02	31.13	29.68	28.71	28.86	28.97	29.14	29.30	29.45	29.63	36.41	36.72
2026	38.12	38.24	35.71	34.22	34.16	34.30	34.50	34.69	34.85	35.30	41.97	41.66
2027	38.89	38.80	37.17	35.15	34.92	35.06	35.03	35.35	35.50	36.00	43.42	43.18
2028	40.43	40.42	39.07	36.57	36.40	36.57	36.42	36.75	37.06	37.76	45.77	44.65
2029	44.23	44.16	41.40	38.91	38.14	38.32	37.88	38.23	38.78	39.51	48.54	48.28
2030	46.80	46.74	44.07	41.82	41.60	41.77	41.81	42.20	42.32	42.88	51.62	51.90
2031	47.78	47.72	44.99	42.70	42.47	42.65	42.69	43.09	43.21	43.78	52.69	52.98
2032	51.38	51.33	48.10	45.71	45.49	45.68	45.76	46.18	46.29	46.89	56.39	56.94
2033	52.77	52.72	49.38	46.93	46.71	46.90	46.99	47.42	47.53	48.14	57.88	58.47
2034	54.12	54.08	50.61	48.10	47.88	48.08	48.17	48.62	48.73	49.35	59.34	59.97
2035	55.66	55.62	52.02	49.46	49.23	49.44	49.54	50.00	50.10	50.74	60.98	61.65
2036	57.04	56.99	53.33	50.72	50.49	50.70	50.80	51.26	51.37	52.02	62.46	63.15
2037	58.43	58.38	54.65	51.99	51.75	51.97	52.06	52.54	52.65	53.32	63.95	64.65
2038	59.88	59.84	56.03	53.32	53.08	53.30	53.40	53.88	54.00	54.67	65.52	66.23
2039	61.13	61.08	57.20	54.44	54.19	54.42	54.52	55.02	55.13	55.82	66.87	67.60
2040	62.75	62.70	58.75	55.93	55.68	55.91	56.01	56.52	56.64	57.34	68.60	69.34
2041	64.04	63.98	59.95	57.08	56.83	57.06	57.17	57.68	57.80	58.52	70.00	70.76

					T	ABLE 3a						
					Avoi	ded Cost	ts					
				Standard	I Fixed P	rice Optic	on for So	lar QF				
				0	n-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	28.21	22.46	15.61	14.71	12.46	16.96	23.96	26.96	24.96	23.71	26.71	31.46
2017	29.96	28.21	24.71	20.96	19.46	20.46	27.96	30.96	29.46	27.71	28.71	33.71
2018	31.71	31.11	28.11	22.13	21.28	21.28	29.93	33.37	30.63	28.61	31.86	35.71
2019	33.94	31.95	27.97	23.70	22.00	23.13	31.67	35.08	33.37	31.38	32.52	38.21
2020	35.74	33.64	29.45	24.95	23.15	24.35	33.34	36.94	35.14	33.04	34.24	40.24
2021	33.98	33.89	31.96	31.24	30.96	31.05	31.16	31.28	31.39	32.03	35.15	35.27
2022	34.92	34.75	33.98	33.04	32.72	32.82	32.94	33.08	33.20	33.74	37.28	37.61
2023	37.09	36.90	35.52	34.32	34.21	34.31	34.44	34.58	34.71	35.26	38.69	38.83
2024	38.86	38.54	37.36	35.98	35.79	35.90	36.04	36.19	36.32	36.88	41.18	41.33
2025	41.08	41.19	39.73	38.77	38.92	39.03	39.19	39.36	39.51	39.69	46.46	46.78
2026	48.37	48.49	45.97	44.48	44.42	44.56	44.75	44.94	45.10	45.56	52.22	51.91
2027	49.34	49.25	47.62	45.61	45.38	45.51	45.48	45.81	45.95	46.45	53.87	53.63
2028	51.08	51.07	49.72	47.22	47.06	47.22	47.07	47.40	47.72	48.41	56.42	55.31
2029	55.08	55.01	52.26	49.77	48.99	49.17	48.73	49.08	49.63	50.36	59.40	59.13
2030	57.87	57.81	55.14	52.89	52.67	52.84	52.88	53.27	53.39	53.95	62.69	62.97
2031	59.07	59.00	56.28	53.98	53.76	53.93	53.98	54.37	54.49	55.06	63.98	64.26
2032	62.83	62.78	59.56	57.16	56.94	57.13	57.21	57.64	57.75	58.34	67.85	68.39
2033	64.49	64.44	61.09	58.64	58.42	58.62	58.70	59.14	59.25	59.86	69.60	70.18
2034	66.10	66.05	62.58	60.08	59.85	60.05	60.14	60.59	60.70	61.32	71.31	71.94
2035	67.84	67.79	64.20	61.64	61.41	61.62	61.71	62.17	62.28	62.92	73.16	73.83
2036	69.43	69.38	65.72	63.11	62.88	63.09	63.19	63.66	63.77	64.42	74.85	75.54
2037	71.08	71.04	67.30	64.64	64.40	64.62	64.72	65.20	65.31	65.97	76.61	77.31
2038	72.78	72.73	68.93	66.22	65.98	66.20	66.30	66.78	66.90	67.57	78.42	79.13
2039	74.28	74.23	70.35	67.58	67.34	67.56	67.67	68.16	68.28	68.97	80.02	80.75
2040	76.15	76.10	72.15	69.33	69.08	69.31	69.42	69.92	70.04	70.74	82.01	82.75
2041	77.69	77.64	73.61	70.74	70.48	70.72	70.82	71.34	71.46	72.17	83.66	84.41

					TA	ABLE 3b						
					Avoi	ded Cost	ts					
				Standard	I Fixed P	rice Optic	on for So	lar QF				
				0	ff-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	25.61	20.71	13.96	11.41	6.31	10.11	15.71	20.96	20.96	21.21	23.46	26.71
2017	25.71	24.21	22.21	15.71	13.71	12.71	19.71	25.21	25.46	24.71	25.71	27.96
2018	26.17	28.12	25.56	19.46	14.68	12.54	19.71	27.04	26.93	25.35	28.20	30.62
2019	29.84	28.09	25.75	18.15	15.81	14.64	22.83	29.26	29.55	28.67	29.84	32.47
2020	31.75	29.88	27.38	19.28	16.79	15.54	24.27	31.12	31.43	30.50	31.75	34.55
2021	28.88	28.79	26.86	26.15	25.87	25.95	26.07	26.19	26.30	26.94	30.06	30.18
2022	29.73	29.56	28.79	27.85	27.53	27.63	27.75	27.88	28.00	28.54	32.09	32.42
2023	31.78	31.59	30.21	29.01	28.90	29.00	29.14	29.27	29.40	29.95	33.38	33.52
2024	33.48	33.16	31.98	30.60	30.41	30.52	30.66	30.81	30.95	31.51	35.80	35.96
2025	35.58	35.69	34.24	33.27	33.42	33.53	33.70	33.86	34.01	34.19	40.97	41.28
2026	42.77	42.89	40.36	38.87	38.81	38.95	39.15	39.34	39.50	39.95	46.62	46.31
2027	43.63	43.54	41.91	39.89	39.66	39.80	39.77	40.09	40.24	40.74	48.16	47.92
2028	45.26	45.25	43.90	41.40	41.23	41.40	41.25	41.58	41.89	42.59	50.60	49.48
2029	49.15	49.08	46.32	43.83	43.06	43.24	42.80	43.15	43.70	44.43	53.46	53.20
2030	51.82	51.76	49.09	46.84	46.62	46.79	46.83	47.22	47.34	47.90	56.64	56.92
2031	52.90	52.84	50.11	47.82	47.59	47.77	47.81	48.21	48.33	48.90	57.81	58.10
2032	56.59	56.54	53.31	50.92	50.70	50.89	50.97	51.39	51.50	52.10	61.60	62.15
2033	58.08	58.03	54.69	52.24	52.02	52.21	52.30	52.73	52.84	53.45	63.19	63.78
2034	59.54	59.50	56.03	53.52	53.30	53.50	53.59	54.04	54.15	54.77	64.76	65.39
2035	61.18	61.14	57.54	54.98	54.75	54.96	55.06	55.52	55.62	56.26	66.50	67.17
2036	62.67	62.62	58.96	56.35	56.12	56.33	56.43	56.89	57.00	57.65	68.09	68.78
2037	64.17	64.12	60.39	57.73	57.49	57.71	57.80	58.28	58.39	59.06	69.69	70.39
2038	65.73	65.69	61.88	59.17	58.93	59.15	59.25	59.73	59.85	60.52	71.37	72.08
2039	67.09	67.04	63.16	60.40	60.15	60.38	60.48	60.98	61.09	61.78	72.83	73.56
2040	68.83	68.78	64.83	62.01	61.76	61.99	62.09	62.60	62.72	63.42	74.68	75.42
2041	70.23	70.17	66.14	63.27	63.02	63.25	63.36	63.87	63.99	64.71	76.19	76.95

PRICING OPTIONS FOR STANDARD PPA (Continued)

2) Renewable Fixed Price Option

The Renewable Fixed Price Option is based on Renewable Avoided Costs. It is available only to Renewable QFs that generate electricity from a renewable energy source that may be used by the Company to comply with the Oregon Renewable Portfolio Standard as set forth in ORS 469A.005 to 469A.210.

This option is available for a maximum term of 15 years. Prices will be as established at the time the Standard PPA is executed and will be equal to the Renewable Avoided Costs in Tables 4a and 4b, 5a and 5b, or 6a and 6b, depending on the type of QF, effective at execution. QFs using any resource type other than wind and solar are assumed to be Base Load QFs.

Sellers will retain all Environmental Attributes generated by the facility during the Renewable Resource Sufficiency Period. A Renewable QF choosing the Renewable Fixed Price Option must cede all RPS Attributes generated by the facility to the Company from the start of the Renewable Resource Deficiency Period through the remainder of the PPA term.

Prices paid to the Seller under the Renewable Fixed Price Option include adjustments for the capacity contribution of the QF resource type relative to that of the avoided proxy resource. Both Wind QF resources (Tables 5a and 5b) and the avoided proxy resource, the basis used to determine Renewable Avoided Costs for the Renewable Fixed Price Option, are assumed to have a capacity contribution to peak of 5%. The capacity contribution for Solar QF resources (Tables 6a and 6b) is assumed to be 5%. The capacity contribution for Base Load QF resources (Tables 4a and 4b) is assumed to be 100%.

The Renewable Avoided Costs during the Renewable Resource Deficiency Period reflect an increase for avoided wind integration costs, shown in Table 7.

Prices paid to the Seller under the Renewable Fixed Price Option for Wind QFs (Tables 5a and 5b) include a reduction for the wind integration costs in Table 7, which cancels out wind integration costs included in the Renewable Avoided Costs during the Renewable Resource Deficiency Period. However, if the Wind QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the wind integration charges in Table 7, in addition to the prices listed in Tables 5a and 5b.

Sellers with PPAs exceeding 15 years will receive pricing equal to the Mid-C Index Price for all years up to five in excess of the initial 15.

					T.	ABLE 4a						
				F	Renewabl	e Avoide	d Costs					
			Rer	newable l	Fixed Price	ce Option	for Base	e Load Q	F			
				0	n-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	28.36	22.61	15.76	14.86	12.61	17.11	24.11	27.11	25.11	23.86	26.86	31.61
2017	30.11	28.36	24.86	21.11	19.61	20.61	28.11	31.11	29.61	27.86	28.86	33.86
2018	31.86	31.26	28.26	22.28	21.43	21.43	30.08	33.52	30.78	28.76	32.01	35.86
2019	34.10	32.11	28.13	23.86	22.16	23.29	31.83	35.24	33.53	31.54	32.68	38.37
2020	115.34	115.32	114.56	115.02	118.22	117.33	117.01	116.89	115.60	114.63	115.47	114.45
2021	117.94	118.18	116.67	117.75	120.59	119.83	119.26	119.77	118.26	117.25	118.55	117.22
2022	120.48	120.36	118.46	120.19	123.17	122.14	121.69	121.65	120.55	119.55	120.98	119.53
2023	123.26	122.83	120.85	122.92	125.37	124.64	124.29	123.92	123.08	121.92	123.63	122.53
2024	124.86	125.01	123.06	125.07	127.80	126.78	126.67	126.41	126.22	123.83	124.83	124.96
2025	127.73	128.05	125.86	128.21	131.66	130.48	129.53	129.66	128.84	126.59	127.76	127.41
2026	130.91	130.58	129.12	131.30	135.76	132.28	132.28	132.69	132.40	129.34	131.17	130.23
2027	133.47	133.03	131.38	133.50	139.48	134.88	134.51	135.95	134.79	131.96	133.26	132.78
2028	135.95	134.91	132.89	136.24	141.79	136.93	137.64	137.65	136.77	134.76	135.84	135.06
2029	138.81	138.57	135.91	139.29	149.30	140.74	140.82	140.82	140.86	137.50	138.32	138.21
2030	141.68	141.39	139.11	142.00	153.18	145.20	143.05	142.93	144.31	140.18	140.75	140.79
2031	144.29	143.79	142.17	145.52	156.10	149.27	145.71	146.65	146.86	143.04	144.15	143.71
2032	146.51	146.00	144.35	147.76	158.51	151.58	147.95	148.91	149.13	145.24	146.37	145.92
2033	149.91	149.40	147.71	151.19	162.18	155.09	151.39	152.37	152.59	148.62	149.77	149.31
2034	152.96	152.43	150.71	154.26	165.46	158.24	154.46	155.46	155.68	151.64	152.81	152.35
2035	155.76	155.22	153.46	157.08	168.50	161.14	157.29	158.31	158.54	154.41	155.60	155.13
2036	158.31	157.76	155.97	159.65	171.26	163.78	159.86	160.90	161.13	156.94	158.15	157.67
2037	161.83	161.27	159.44	163.20	175.07	167.42	163.42	164.48	164.71	160.43	161.67	161.18
2038	164.95	164.38	162.52	166.35	178.45	170.65	166.57	167.65	167.89	163.52	164.79	164.29
2039	168.13	167.55	165.66	169.56	181.89	173.94	169.79	170.89	171.13	166.68	167.97	167.46
2040	171.05	170.46	168.54	172.51	185.04	176.96	172.74	173.85	174.10	169.58	170.89	170.37
2041	174.69	174.08	172.11	176.17	188.98	180.72	176.40	177.55	177.80	173.18	174.52	173.99

					TA	ABLE 4b						
				F	Renewabl	e Avoide	d Costs					
			Rer	newable F	ixed Pric	e Option	for Base	Load Q	F			
				0	ff-Peak F	orecast (\$/MWH)					
				_				-	_			
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	25.76	20.86	14.11	11.56	6.46	10.26	15.86	21.11	21.11	21.36	23.61	26.86
2017	25.86	24.36	22.36	15.86	13.86	12.86	19.86	25.36	25.61	24.86	25.86	28.11
2018	26.32	28.27	25.71	19.61	14.83	12.69	19.86	27.19	27.08	25.50	28.35	30.77
2019	30.00	28.25	25.91	18.31	15.97	14.80	22.99	29.42	29.71	28.83	30.00	32.63
2020	62.76	63.02	64.56	63.31	59.92	60.16	60.45	61.61	62.52	63.74	63.55	63.99
2021	64.93	64.15	65.85	64.48	61.58	61.62	62.27	62.62	63.78	65.82	63.38	65.09
2022	65.85	65.52	67.77	65.49	62.45	62.82	64.33	63.35	65.00	67.04	64.42	66.29
2023	66.70	66.75	69.10	67.28	62.84	64.01	65.40	64.85	66.14	68.41	65.38	67.63
2024	67.25	67.31	70.47	67.09	63.18	65.92	64.75	65.12	66.62	68.68	67.42	68.05
2025	68.62	68.60	71.94	68.08	63.17	66.28	66.12	67.12	67.23	70.19	69.68	69.06
2026	68.95	69.85	72.28	68.56	63.85	67.22	67.05	67.75	67.05	71.12	69.85	69.89
2027	71.31	71.29	73.13	70.34	63.69	68.45	68.79	68.16	68.57	73.22	70.67	71.18
2028	72.28	72.90	75.41	72.10	63.09	69.98	70.15	68.82	70.20	73.79	71.48	73.41
2029	72.78	73.60	76.79	73.50	58.25	70.29	71.37	70.00	71.53	74.58	73.61	74.68
2030	73.91	74.82	78.36	73.64	58.00	70.89	72.02	72.19	72.00	75.99	75.36	76.23
2031	75.51	76.70	79.40	74.00	59.17	70.67	73.55	73.71	72.16	77.24	77.07	76.31
2032	76.76	77.97	80.71	75.23	60.15	71.83	74.76	74.93	73.35	78.52	78.34	77.57
2033	78.46	79.69	82.50	76.89	61.48	73.42	76.42	76.58	74.97	80.25	80.07	79.29
2034	79.97	81.23	84.09	78.37	62.66	74.84	77.89	78.06	76.42	81.80	81.62	80.82
2035	81.52	82.80	85.71	79.88	63.87	76.28	79.39	79.57	77.89	83.38	83.19	82.38
2036	82.86	84.17	87.13	81.20	64.93	77.54	80.70	80.88	79.18	84.76	84.57	83.74
2037	84.69	86.03	89.05	83.00	66.36	79.25	82.49	82.67	80.93	86.63	86.44	85.59
2038	86.33	87.69	90.77	84.60	67.64	80.78	84.08	84.26	82.49	88.30	88.11	87.24
2039	87.99	89.38	92.52	86.23	68.95	82.34	85.70	85.89	84.08	90.01	89.81	88.92
2040	89.45	90.85	94.05	87.66	70.09	83.70	87.12	87.31	85.47	91.49	91.29	90.39
2041	91.42	92.86	96.13	89.59	71.63	85.55	89.04	89.24	87.36	93.51	93.31	92.39

					T.	ABLE 5a						
				F	Renewabl	e Avoide	d Costs					
			I	Renewab	le Fixed F	Price Opt	ion for W	/ind QF				
				0	n-Peak F	orecast	\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	24.52	18.77	11.92	11.02	8.77	13.27	20.27	23.27	21.27	20.02	23.02	27.77
2017	26.20	24.45	20.95	17.20	15.70	16.70	24.20	27.20	25.70	23.95	24.95	29.95
2018	27.87	27.27	24.27	18.29	17.44	17.44	26.09	29.53	26.79	24.77	28.02	31.87
2019	30.03	28.04	24.06	19.79	18.09	19.22	27.76	31.17	29.46	27.47	28.61	34.30
2020	75.38	75.37	74.61	75.06	78.26	77.37	77.05	76.93	75.64	74.67	75.51	74.49
2021	77.10	77.33	75.83	76.90	79.75	78.99	78.41	78.92	77.41	76.40	77.70	76.38
2022	78.85	78.72	76.82	78.56	81.53	80.51	80.05	80.02	78.92	77.92	79.34	77.90
2023	80.71	80.27	78.29	80.37	82.82	82.08	81.73	81.37	80.53	79.36	81.08	79.97
2024	81.74	81.89	79.93	81.95	84.68	83.66	83.55	83.28	83.10	80.71	81.71	81.84
2025	83.64	83.97	81.78	84.13	87.57	86.40	85.44	85.57	84.75	82.51	83.68	83.32
2026	85.97	85.64	84.18	86.37	90.82	87.34	87.34	87.75	87.46	84.40	86.23	85.29
2027	87.67	87.23	85.57	87.69	93.67	89.07	88.71	90.15	88.99	86.16	87.45	86.98
2028	89.26	88.22	86.20	89.55	95.10	90.24	90.95	90.96	90.08	88.07	89.15	88.37
2029	91.22	90.98	88.32	91.70	101.72	93.16	93.23	93.23	93.28	89.92	90.73	90.62
2030	93.17	92.88	90.60	93.49	104.67	96.69	94.54	94.42	95.80	91.67	92.24	92.28
2031	94.84	94.34	92.72	96.07	106.65	99.82	96.26	97.20	97.42	93.59	94.70	94.26
2032	96.40	95.90	94.24	97.65	108.40	101.47	97.85	98.80	99.02	95.13	96.26	95.82
2033	98.55	98.03	96.34	99.82	110.81	103.72	100.02	101.00	101.22	97.25	98.40	97.95
2034	100.44	99.91	98.19	101.74	112.94	105.72	101.94	102.94	103.17	99.12	100.29	99.83
2035	102.38	101.85	100.09	103.71	115.13	107.76	103.92	104.93	105.16	101.04	102.23	101.76
2036	104.06	103.51	101.72	105.40	117.01	109.53	105.61	106.65	106.88	102.69	103.90	103.42
2037	106.37	105.81	103.99	107.74	119.61	111.96	107.96	109.02	109.26	104.97	106.21	105.72
2038	108.42	107.86	105.99	109.82	121.92	114.12	110.05	111.12	111.37	107.00	108.26	107.76
2039	110.52	109.94	108.04	111.95	124.27	116.33	112.17	113.27	113.52	109.07	110.36	109.85
2040	112.32	111.73	109.81	113.77	126.31	118.23	114.00	115.12	115.37	110.85	112.16	111.64
2041	114.83	114.23	112.26	116.31	129.12	120.86	116.55	117.69	117.95	113.32	114.66	114.13

					TA	ABLE 5b						
				F	Renewabl	e Avoide	d Costs					
			F		le Fixed F			ind QF				
				0	ff-Peak F	orecast (\$/MWH)					
	_					_		_	_			
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	21.92	17.02	10.27	7.72	2.62	6.42	12.02	17.27	17.27	17.52	19.77	23.02
2017	21.95	20.45	18.45	11.95	9.95	8.95	15.95	21.45	21.70	20.95	21.95	24.20
2018	22.33	24.28	21.72	15.62	10.84	8.70	15.87	23.20	23.09	21.51	24.36	26.78
2019	25.93	24.18	21.84	14.24	11.90	10.73	18.92	25.35	25.64	24.76	25.93	28.56
2020	58.61	58.87	60.41	59.16	55.77	56.01	56.30	57.46	58.37	59.59	59.40	59.84
2021	60.70	59.92	61.62	60.25	57.35	57.39	58.04	58.39	59.55	61.59	59.15	60.86
2022	61.54	61.21	63.46	61.18	58.14	58.51	60.02	59.04	60.69	62.73	60.11	61.98
2023	62.31	62.36	64.71	62.89	58.45	59.62	61.01	60.46	61.75	64.02	60.99	63.24
2024	62.78	62.84	66.00	62.62	58.71	61.45	60.28	60.65	62.15	64.21	62.95	63.58
2025	64.06	64.04	67.38	63.52	58.61	61.72	61.56	62.56	62.67	65.63	65.12	64.50
2026	64.30	65.20	67.63	63.91	59.20	62.57	62.40	63.10	62.40	66.47	65.20	65.24
2027	66.57	66.55	68.39	65.60	58.95	63.71	64.05	63.42	63.83	68.48	65.93	66.44
2028	67.45	68.07	70.58	67.27	58.26	65.15	65.32	63.99	65.37	68.96	66.65	68.58
2029	67.86	68.68	71.87	68.58	53.33	65.37	66.45	65.08	66.61	69.66	68.69	69.76
2030	68.89	69.80	73.34	68.62	52.98	65.87	67.00	67.17	66.98	70.97	70.34	71.21
2031	70.39	71.58	74.28	68.88	54.05	65.55	68.43	68.59	67.04	72.12	71.95	71.19
2032	71.55	72.76	75.50	70.02	54.94	66.62	69.55	69.72	68.14	73.31	73.13	72.36
2033	73.15	74.38	77.19	71.58	56.17	68.11	71.11	71.27	69.66	74.94	74.76	73.98
2034	74.55	75.81	78.67	72.95	57.24	69.42	72.47	72.64	71.00	76.38	76.20	75.40
2035	76.00	77.28	80.19	74.36	58.35	70.76	73.87	74.05	72.37	77.86	77.67	76.86
2036	77.23	78.54	81.50	75.57	59.30	71.91	75.07	75.25	73.55	79.13	78.94	78.11
2037	78.95	80.29	83.31	77.26	60.62	73.51	76.75	76.93	75.19	80.89	80.70	79.85
2038	80.48	81.84	84.92	78.75	61.79	74.93	78.23	78.41	76.64	82.45	82.26	81.39
2039	82.03	83.42	86.56	80.27	62.99	76.38	79.74	79.93	78.12	84.05	83.85	82.96
2040	83.37	84.77	87.97	81.58	64.01	77.62	81.04	81.23	79.39	85.41	85.21	84.31
2041	85.23	86.67	89.94	83.40	65.44	79.36	82.85	83.05	81.17	87.32	87.12	86.20

					T.	ABLE 6a						
				F	Renewabl	e Avoide	d Costs					
				Renewab	le Fixed F	Price Opt	ion for S	olar QF				
				0	n-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	28.36	22.61	15.76	14.86	12.61	17.11	24.11	27.11	25.11	23.86	26.86	31.61
2017	30.11	28.36	24.86	21.11	19.61	20.61	28.11	31.11	29.61	27.86	28.86	33.86
2018	31.86	31.26	28.26	22.28	21.43	21.43	30.08	33.52	30.78	28.76	32.01	35.86
2019	34.10	32.11	28.13	23.86	22.16	23.29	31.83	35.24	33.53	31.54	32.68	38.37
2020	78.62	78.60	77.84	78.30	81.50	80.60	80.29	80.17	78.88	77.91	78.74	77.73
2021	80.39	80.63	79.12	80.20	83.04	82.28	81.71	82.22	80.71	79.70	81.00	79.67
2022	82.21	82.08	80.18	81.92	84.89	83.87	83.41	83.38	82.27	81.27	82.70	81.25
2023	84.12	83.69	81.71	83.78	86.23	85.50	85.15	84.78	83.94	82.78	84.50	83.39
2024	85.22	85.37	83.41	85.43	88.16	87.14	87.03	86.76	86.58	84.19	85.19	85.32
2025	87.19	87.52	85.33	87.68	91.12	89.95	88.99	89.12	88.30	86.06	87.23	86.87
2026	89.59	89.26	87.80	89.99	94.44	90.96	90.96	91.37	91.08	88.02	89.85	88.91
2027	91.36	90.92	89.26	91.39	97.36	92.76	92.40	93.84	92.68	89.85	91.14	90.67
2028	93.02	91.98	89.96	93.31	98.86	94.00	94.71	94.72	93.84	91.84	92.91	92.13
2029	95.05	94.81	92.15	95.53	105.55	96.99	97.06	97.06	97.11	93.75	94.56	94.45
2030	97.08	96.79	94.51	97.40	108.58	100.60	98.45	98.33	99.71	95.58	96.15	96.19
2031	98.83	98.33	96.70	100.05	110.63	103.81	100.25	101.19	101.40	97.58	98.69	98.25
2032	100.47	99.96	98.30	101.71	112.47	105.53	101.91	102.87	103.08	99.20	100.32	99.88
2033	102.68	102.16	100.47	103.95	114.95	107.86	104.16	105.14	105.36	101.38	102.53	102.08
2034	104.66	104.13	102.41	105.96	117.16	109.94	106.16	107.16	107.38	103.34	104.51	104.05
2035	106.68	106.15	104.39	108.01	119.43	112.06	108.21	109.23	109.46	105.34	106.53	106.06
2036	108.44	107.90	106.11	109.79	121.40	113.91	110.00	111.04	111.27	107.08	108.29	107.81
2037	110.84	110.28	108.46	112.21	124.08	116.43	112.43	113.49	113.73	109.44	110.68	110.19
2038	112.98	112.41	110.55	114.38	126.47	118.68	114.60	115.68	115.92	111.55	112.82	112.32
2039	115.16	114.58	112.68	116.59	128.92	120.97	116.81	117.91	118.16	113.71	115.00	114.49
2040	117.06	116.47	114.54	118.51	131.04	122.96	118.74	119.86	120.11	115.58	116.89	116.37
2041	119.65	119.05	117.07	121.13	133.94	125.68	121.37	122.51	122.76	118.14	119.48	118.95

					TA	ABLE 6b						
				F	Renewabl	e Avoide	d Costs					
			F	Renewab	le Fixed F	Price Opt	ion for So	olar QF				
				0	ff-Peak F	orecast (\$/MWH)					
									_			
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	25.76	20.86	14.11	11.56	6.46	10.26	15.86	21.11	21.11	21.36	23.61	26.86
2017	25.86	24.36	22.36	15.86	13.86	12.86	19.86	25.36	25.61	24.86	25.86	28.11
2018	26.32	28.27	25.71	19.61	14.83	12.69	19.86	27.19	27.08	25.50	28.35	30.77
2019	30.00	28.25	25.91	18.31	15.97	14.80	22.99	29.42	29.71	28.83	30.00	32.63
2020	62.76	63.02	64.56	63.31	59.92	60.16	60.45	61.61	62.52	63.74	63.55	63.99
2021	64.93	64.15	65.85	64.48	61.58	61.62	62.27	62.62	63.78	65.82	63.38	65.09
2022	65.85	65.52	67.77	65.49	62.45	62.82	64.33	63.35	65.00	67.04	64.42	66.29
2023	66.70	66.75	69.10	67.28	62.84	64.01	65.40	64.85	66.14	68.41	65.38	67.63
2024	67.25	67.31	70.47	67.09	63.18	65.92	64.75	65.12	66.62	68.68	67.42	68.05
2025	68.62	68.60	71.94	68.08	63.17	66.28	66.12	67.12	67.23	70.19	69.68	69.06
2026	68.95	69.85	72.28	68.56	63.85	67.22	67.05	67.75	67.05	71.12	69.85	69.89
2027	71.31	71.29	73.13	70.34	63.69	68.45	68.79	68.16	68.57	73.22	70.67	71.18
2028	72.28	72.90	75.41	72.10	63.09	69.98	70.15	68.82	70.20	73.79	71.48	73.41
2029	72.78	73.60	76.79	73.50	58.25	70.29	71.37	70.00	71.53	74.58	73.61	74.68
2030	73.91	74.82	78.36	73.64	58.00	70.89	72.02	72.19	72.00	75.99	75.36	76.23
2031	75.51	76.70	79.40	74.00	59.17	70.67	73.55	73.71	72.16	77.24	77.07	76.31
2032	76.76	77.97	80.71	75.23	60.15	71.83	74.76	74.93	73.35	78.52	78.34	77.57
2033	78.46	79.69	82.50	76.89	61.48	73.42	76.42	76.58	74.97	80.25	80.07	79.29
2034	79.97	81.23	84.09	78.37	62.66	74.84	77.89	78.06	76.42	81.80	81.62	80.82
2035	81.52	82.80	85.71	79.88	63.87	76.28	79.39	79.57	77.89	83.38	83.19	82.38
2036	82.86	84.17	87.13	81.20	64.93	77.54	80.70	80.88	79.18	84.76	84.57	83.74
2037	84.69	86.03	89.05	83.00	66.36	79.25	82.49	82.67	80.93	86.63	86.44	85.59
2038	86.33	87.69	90.77	84.60	67.64	80.78	84.08	84.26	82.49	88.30	88.11	87.24
2039	87.99	89.38	92.52	86.23	68.95	82.34	85.70	85.89	84.08	90.01	89.81	88.92
2040	89.45	90.85	94.05	87.66	70.09	83.70	87.12	87.31	85.47	91.49	91.29	90.39
2041	91.42	92.86	96.13	89.59	71.63	85.55	89.04	89.24	87.36	93.51	93.31	92.39

WIND INTEGRATION

TAE	BLE 7
Wind In	tegration
Year	Cost
2015	3.77
2016	3.84
2017	3.91
2018	3.99
2019	4.07
2020	4.15
2021	4.23
2022	4.31
2023	4.39
2024	4.47
2025	4.56
2026	4.65
2027	4.74
2028	4.83
2029	4.92
2030	5.02
2031	5.12
2032	5.21
2033	5.31
2034	5.42
2035	5.52
2036	5.63
2037	5.74
2038	5.85
2039	5.96
2040	6.08

MONTHLY SERVICE CHARGE

Each separately metered QF not associated with a retail Customer account will be charged \$10.00 per month.

INSURANCE REQUIREMENTS

The following insurance requirements are applicable to Sellers with a Standard PPA:

- 1) QFs with nameplate capacity ratings greater than 200 kW are required to secure and maintain a prudent amount of general liability insurance. The Seller must certify to the Company that it is maintaining general liability insurance coverage for each QF at prudent amounts. A prudent amount will be deemed to mean liability insurance coverage for both bodily injury and property damage liability in the amount of not less than \$1,000,000 each occurrence combined single limit, which limits may be required to be increased or decreased by the Company as the Company determines in its reasonable judgment, that economic conditions or claims experience may warrant.
- 2) Such insurance will include an endorsement naming the Company as an additional insured insofar as liability arising out of operations under this schedule and a provision that such liability policies will not be canceled or their limits reduced without 30 days' written notice to the Company. The Seller will furnish the Company with certificates of insurance together with the endorsements required herein. The Company will have the right to inspect the original policies of such insurance.
- 3) QFs with a design capacity of 200 kW or less are encouraged to pursue liability insurance on their own. The Oregon Public Utility Commission in Order No. 05-584 determined that it is inappropriate to require QFs that have a design capacity of 200 kW or less to obtain general liability insurance.

TRANSMISSION AGREEMENTS

If the QF is located outside the Company's service territory, the Seller is responsible for the transmission of power at its cost to the Company's service territory.

INTERCONNECTION REQUIREMENTS

Except as otherwise provided in a generation Interconnection Agreement between the Company and Seller, if the QF is located within the Company's service territory, switching equipment capable of isolating the QF from the Company's system will be accessible to the Company at all times. At the Company's option, the Company may operate the switching equipment described above if, in the sole opinion of the Company, continued operation of the QF in connection with the utility's system may create or contribute to a system emergency.

INTERCONNECTION REQUIREMENTS (Continued)

The QF owner interconnecting with the Company's distribution system must comply with all requirements for interconnection as established pursuant to Commission rule, in the Company's Rules and Regulations (Rule C) or the Company's Interconnection Procedures contained in its FERC Open Access Transmission Tariff (OATT), as applicable. The Seller will bear full responsibility for the installation and safe operation of the interconnection facilities.

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE PRICING UNDER THE STANDARD PPA

A QF will be eligible to receive pricing under the Standard PPA if the nameplate capacity of the QF, together with any other electric generating facility using the same motive force, owned or controlled by the Same Person(s) or Affiliated Person(s), and located at the Same Site, does not exceed 10 MW. A Community-Based or Family-Owned QF is exempt from these restrictions.

Definition of Community-Based

- a. A community project (or a community sponsored project) must have a recognized and established organization located within the county of the project or within 50 miles of the project that has a genuine role in helping the project be developed and must have some not insignificant continuing role with or interest in the project after it is completed and placed in service.
- b. After excluding the passive investor whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit, the equity (ownership) interests in a community sponsored project must be owned in substantial percentage (80 percent or more) by the following persons (individuals and entities): (i) the sponsoring organization, or its controlled affiliates; (ii) members of the sponsoring organization (if it is a membership organization) or owners of the sponsorship organization (if it is privately owned); (iii) persons who live in the county in which the project is located or who live a county adjoining the county in which the project is located; or (iv) units of local government, charities, or other established nonprofit organizations active either in the county in which the project is located or active in a county adjoining the county in which the project is located.

Definition of Family-Owned

After excluding the ownership interest of the passive investor whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit, five or fewer individuals own 50 percent or more of the equity of the project entity, or fifteen or fewer individuals own 90 percent or more of the project entity. A "look through" rule applies to closely held entities that hold the project entity, so that equity held by LLCs, trusts, estates, corporations, partnerships or other similar entities is considered held by the equity owners of the look through entity. An individual is a natural person. In counting to five or fifteen, spouses or children of an equity owner of the project owner who also have an equity interest are aggregated and counted as a single individual.

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE PRICING UNDER THE STANDARD PPA (Continued)

Definition of Person(s) or Affiliated Person(s)

As used above, the term "Same Person(s)" or "Affiliated Person(s)" means a natural person or persons or any legal entity or entities sharing common ownership, management or acting jointly or in concert with or exercising influence over the policies or actions of another person or entity. However, two facilities will not be held to be owned or controlled by the Same Person(s) or Affiliated Person(s) solely because they are developed by a single entity.

Furthermore, two facilities will not be held to be owned or controlled by the Same Person(s) or Affiliated Person(s) if such common person or persons is a "passive investor" whose ownership interest in the QF is primarily related to utilizing production tax credits, green tag values and MACRS depreciation as the primary ownership benefit and the facilities at issue are independent family-owned or community-based projects. A unit of Oregon local government may also be a "passive investor" in a community-based project if the local governmental unit demonstrates that it will not have an equity ownership interest in or exercise any control over the management of the QF and that its only interest is a share of the cash flow from the QF, which share will not exceed 20%. The 20% cash flow share limit may only be exceeded for good cause shown and only with the prior approval of the Commission.

Definition of Same Site

For purposes of the foregoing, generating facilities are considered to be located at the same site as the QF for which qualification for pricing under the Standard PPA is sought if they are located within a five-mile radius of any generating facilities or equipment providing fuel or motive force associated with the QF for which qualification for pricing under the Standard PPA is sought.

Definition of Shared Interconnection and Infrastructure

QFs otherwise meeting the above-described separate ownership test and thereby qualified for entitlement to pricing under the Standard PPA will not be disqualified by utilizing an interconnection or other infrastructure not providing motive force or fuel that is shared with other QFs qualifying for pricing under the Standard PPA so long as the use of the shared interconnection complies with the interconnecting utility's safety and reliability standards, interconnection agreement requirements and Prudent Electrical Practices as that term is defined in the interconnecting utility's approved Standard PPA.

OTHER DEFINITIONS

Mid-C Index Price

As used in this schedule, the daily Mid-C Index Price shall be the Day Ahead Intercontinental Exchange ("ICE") for the bilateral OTC market for energy at the Mid-C Physical for Average

OTHER DEFINITIONS (Continued)

On-Peak Power and Average Off-Peak Power found on the following website: https://www.theice.com/products/OTC/Physical-Energy/Electricity. In the event ICE no longer publishes this index, PGE and the Seller agree to select an alternative successor index representative of the Mid-C trading hub.

Definition of RPS Attributes

As used in this schedule, RPS Attributes means all attributes related to the Net Output generated by the Facility that are required in order to provide PGE with "qualifying electricity," as that term is defined in Oregon's Renewable Portfolio Standard Act, Ore. Rev. Stat. 469A.010, in effect at the time of execution of this Agreement. RPS Attributes do not include Environmental Attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity and not needed to ensure that there are zero net emissions associated with the generation of electricity.

Definition of Environmental Attributes

As used in this schedule, Environmental Attributes shall mean any and all claims, credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical, or other substance to the air, soil or water. Environmental Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil, or water such as (subject to the foregoing) sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; and (2) any avoided emissions of carbon dioxide (CO2), methane (CH4), and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere.

Definition of Resource Sufficiency Period

This is the period from the current year through 2020.

Definition of Resource Deficiency Period

This is the period from 2021 through 2034.

Definition of Renewable Resource Sufficiency Period

This is the period from the current year through 2019.

Definition of Renewable Resource Deficiency Period

This is the period from 2020 through 2034.

SCHEDULE 201 (Concluded)

DISPUTE RESOLUTION

Upon request, the QF will provide the purchasing utility with documentation verifying the ownership, management and financial structure of the QF in reasonably sufficient detail to allow the utility to make an initial determination of whether or not the QF meets the above-described criteria for entitlement to pricing under the Standard PPA.

The QF may present disputes to the Commission for resolution using the following process:

The QF may file a complaint asking the Commission to adjudicate disputes regarding the formation of the standard contract. The QF may not file such a complaint during any 15-day period in which the utility has the obligation to respond, but must wait until the 15-day period has passed.

The utility may respond to the complaint within ten days of service.

The Commission will limit its review to the issues identified in the complaint and response, and utilize a process similar to the arbitration process adopted to facilitate the execution of interconnection agreements among telecommunications carriers. See OAR 860, Division 016. The administrative law judge will not act as an arbitrator.

SPECIAL CONDITIONS

- 1. Delivery of energy by Seller will be at a voltage, phase, frequency, and power factor as specified by the Company.
- 2. If the Seller also receives retail Electricity Service from the Company at the same location, any payments under this schedule will be credited to the Seller's retail Electricity Service bill. At the option of the Customer, any net credit over \$10.00 will be paid by check to the Customer.
- 3. Unless required by state or federal law, if the 1978 Public Utility Regulatory Policies Act (PURPA) is repealed, PPAs entered into pursuant to this schedule will not terminate prior to the Standard or Negotiated PPA's termination date.

TERM OF AGREEMENT

Not less than one year and not to exceed 20 years.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM 1829, UM 1830, UM 1831, UM 1832, UM 1833

BLUE MARMOT V LLC (UM 1829)	
BLUE MARMOT VI LLC (UM 1830)	
BLUE MARMOT VII LLC (UM 1831)	
BLUE MARMOT VIII LLC (UM 1832)	
BLUE MARMOT IX LLC (UM 1833)	
Complainants	
VS.	
PORTLAND GENERAL ELECTRIC	
COMPANY	
Defendant	
Pursuant to ORS 756.500.	

EXHIBIT BLUE MARMOT/202 EXECUTED PPAS

October 13, 2017

STANDARD RENEWABLE OFF-SYSTEM VARIABLE POWER PURCHASE

AGREEMENT

THIS AGREEMENT is between <u>Blue Marmot V LLC</u> ("Seller") and Portland General Electric Company ("PGE") (hereinafter each a "Party" or collectively, "Parties") and is effective upon execution by both Parties ("Effective Date").

RECITALS

Seller intends to construct, own, operate and maintain a <u>Solar</u> facility for the generation of electric power located in <u>Lake</u>, County, <u>Oregon at W 120.412 N 42.175</u> with a Nameplate Capacity Rating of <u>10000</u> kilowatt ("kW"), as further described in Exhibit A ("Facility"); and

Seller intends to operate the Facility as a "Qualifying Facility," as such term is defined in Section 3.1.3, below.

Seller shall sell and PGE shall purchase the entire Net Output, as such term is defined in Section 1.21, below, from the Facility in accordance with the terms and conditions of this Agreement.

AGREEMENT

NOW, THEREFORE, the Parties mutually agree as follows:

SECTION 1: DEFINITIONS

When used in this Agreement, the following terms shall have the following meanings:

- 1.1. "As-built Supplement" means the supplement to Exhibit A provided by Seller in accordance with Section 4.3 following completion of construction of the Facility, describing the Facility as actually built.
- 1.2. "Base Hours" is defined as the total number of hours in each Contract Year (8,760 or 8,784 for leap year)
- 1.3. "Billing Period" means from the start of the first day of each calendar month to the end of the last day of each calendar month.
- 1.4. "Cash Escrow" means an agreement by two parties to place money into the custody of a third party for delivery to a grantee only after the fulfillment of the conditions specified.
- 1.5. "Commercial Operation Date" means the date that the Facility is deemed by PGE to be fully operational and reliable. PGE may, at its discretion require, among other things, that all of the following events have occurred:
- 1.5.1. (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from a Licensed

Professional Engineer ("LPE") acceptable to PGE in its reasonable judgment stating that the Facility is able to generate electric power reliably in accordance with the terms and conditions of this Agreement (certifications required under this Section 1.5 can be provided by one or more LPEs);

- 1.5.2. Start-Up Testing of the Facility has been completed in accordance with Section 1.36;
- 1.5.3. (facilities with nameplate under 500 kW exempt from following requirement) After PGE has received notice of completion of Start-Up Testing, PGE has received a certificate addressed to PGE from an LPE stating that the Facility has operated for testing purposes under this Agreement and was continuously mechanically available for operation for a minimum of 120 hours. The Facility must provide ten (10) working days written notice to PGE prior to the start of the initial testing period. If the mechanical availability of the Facility is interrupted during this initial testing period or any subsequent testing period, the Facility shall promptly start a new Test Period and provide PGE forty-eight (48) hours written notice prior to the start of such testing period;
- 1.5.4. (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from an LPE stating that all required interconnection facilities have been constructed and all required interconnection tests have been completed;
- 1.5.5. (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from an LPE stating that Seller has obtained all Required Facility Documents and, if requested by PGE in writing, has provided copies of any or all such requested Required Facility Documents;
- 1.5.6. PGE has received a copy of the executed Generation Interconnection and Transmission Agreements.
- 1.6. "Contract Price" means the applicable price, including on-peak and offpeak prices, as specified in the Schedule.
- 1.7. "Contract Year" means each twelve (12) month period commencing upon the Commercial Operation Date or its anniversary during the Term, except the final Contract Year will be the period from the last anniversary of the Commercial Operation Date during the Term until the end of the Term.
 - 1.8. "Effective Date" has the meaning set forth in Section 2.1.
- 1.9. "Environmental Attributes" shall mean any and all claims, credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical or other substance to the air, soil or water. Environmental Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil or water such as (subject to the foregoing) sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; and (2) any avoided emissions of carbon dioxide (CO2), methane (CH4), and other greenhouse gasses (GHGs) that have been determined by the United Nations

Intergovernmental Panel on Climate Change to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere.

- 1.10. "Facility" has the meaning set forth in the Recitals.
- 1.11. "Generation Interconnection Agreement" means an agreement governing the interconnection of the Facility with <u>PacifiCorp</u> electric system.
- 1.12. "Generation Unit" means each separate electrical generator that contributes toward Nameplate Capacity Rating included in Exhibit A. For solar facilities, a generating unit is a complete solar electrical generation system within the Facility that is able to generate and deliver energy to the Point of Delivery independent of other Generation Units within the same Facility.
- 1.13. "Letter of Credit" means an engagement by a bank or other person made at the request of a customer that the issuer will honor drafts or other demands for payment upon compliance with the conditions specified in the letter of credit.
- 1.14. "Licensed Professional Engineer" or "LPE" means a person who is licensed to practice engineering in the state where the Facility is located, who has no economic relationship, association, or nexus with the Seller, and who is not a representative of a consulting engineer, contractor, designer or other individual involved in the development of the Facility, or of a manufacturer or supplier of any equipment installed in the Facility. Such Licensed Professional Engineer shall be licensed in an appropriate engineering discipline for the required certification being made and be acceptable to PGE in its reasonable judgment.
- 1.15. "Lost Energy" means "Lost Energy" means ((the Guarantee of Mechanical Availability as set forth in 3.1.10 / MAP) X Net Output for a Calendar Year) Net Output for the Calendar Year. Lost Energy shall be zero unless the result of the calculation in this subsection results in a positive number.
- 1.16. "Lost Energy Value" means Lost Energy X the excess of the annual time-weighted average Mid-C Index Price for On Peak Hours and Off Peak Hours over the time weighted average Contract Price for On Peak and Off Peak Hours for the corresponding time period (provided that such excess shall not exceed the Contract Price and further provided that Lost Energy is deemed to be zero prior to reaching the Commercial Operation Date) plus any reasonable costs incurred by PGE to purchase replacement power and/or transmission to deliver the replacement power to the Point of Delivery (For Start-Up Lost Energy Value See 1.35).
- 1.17. "Mechanical Availability Percentage" or "MAP" shall mean that percentage for any Contract Year for the Facility calculated in accordance with the following formula:

MAP = 100 X (Operational Hours) /(Base Hours X Number of Units)

1.18. "Mid-C Index Price" means the Day Ahead Intercontinental Exchange ("ICE") index price for the bilateral OTC market for energy at the Mid-C Physical for Average On Peak Power and Average Off Peak Power found on the following website:

https://www.theice.com/products/OTC/Physical-Energy/Electricity. In the event ICE no longer publishes this index, PGE and the Seller agree to select an alternative successor index representative of the Mid-C trading hub.

- 1.19. "Nameplate Capacity Rating" means the maximum capacity of the Facility as stated by the manufacturer, expressed in kW, which shall not exceed 10,000 kW.
- 1.20. "Net Dependable Capacity" means the maximum capacity the Facility can sustain over a specified period modified for seasonal limitations, if any, and reduced by the capacity required for station service or auxiliaries.
- 1.21. "Net Output" means all energy expressed in kWhs produced by the Facility, less station and other onsite use and less transformation and transmission losses.
- 1.22. "Number of Units" means the number of Generation Units in the Facility as specified in Exhibit A.
 - 1.23. "Off-Peak Hours" has the meaning provided in the Schedule.
 - 1.24. "On-Peak Hours" has the meaning provided in the Schedule.
- 1.25. "Operational Hours" for the Facility means the total across all Generation Units of the number of hours each of the Facility's Generation Units are potentially capable of producing power at its Nameplate Capacity Rating regardless of actual weather conditions, season and the time of day or night, without any mechanical operating constraint or restriction, and potentially capable of delivering such power to the Point of Delivery in a Contract Year. During up to, but not more than, two hundred (200) hours of Planned Maintenance during a Contract Year for each Generation Unit and hours during which an event of Force Majeure exists, a Generation Unit shall be considered potentially capable of delivering such power to the Point of Delivery. For example, in the absence of any Planned Maintenance beyond 200 hours on any Generation Unit or Event of Force Majeure, the Operational Hours for a wind farm with five (5) separate two (2) MW turbines would be 43,800 for a Contract Year.
- 1.26. "Planned Maintenance" means outages scheduled ninety (90) days in advance, with PGE's prior written consent, which shall not be unreasonably withheld.
 - 1.27. "Point of Delivery" means the PGE system.
- 1.28. "Pre-Commercial Operation Date Minimum Net Output" shall mean, unless such MWh is specifically set forth by Seller in Exhibit A, an amount in MWh equal to seventy-five percent (75%) of Nameplate Capacity Rating X thirty percent (30%) for a wind or other renewable QF or fifty percent (50%) for a solar QF X (whole months since the date selected in Section 2.2.1 / 12) X (8760 hours 200 hours (assumed Planned Maintenance)) for each month. If Seller has provided specific expected monthly Net Output amounts for the Facility in Exhibit A, "Pre-Commercial Operation Date Minimum Net Output" shall mean seventy-five percent (75%) X expected net output set forth in Exhibit A for each month.

- 1.29. "Prime Rate" means the publicly announced prime rate or reference rate for commercial loans to large businesses with the highest credit rating in the United States in effect from time to time quoted by Citibank, N.A. If a Citibank, N.A. prime rate is not available, the applicable Prime Rate shall be the announced prime rate or reference rate for commercial loans in effect from time to time quoted by a bank with \$10 billion or more in assets in New York City, N.Y., selected by the Party to whom interest based on the prime rate is being paid.
- 1.30. "Prudent Electrical Practices" means those practices, methods, standards and acts engaged in or approved by a significant portion of the electric power industry in the Western Electricity Coordinating Council that at the relevant time period, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with good business practices, reliability, economy, safety and expedition, and which practices, methods, standards and acts reflect due regard for operation and maintenance standards recommended by applicable equipment suppliers and manufacturers, operational limits, and all applicable laws and regulations. Prudent Electrical Practices are not intended to be limited to the optimum practice, method, standard or act to the exclusion of all others, but rather to those practices, methods and acts generally acceptable or approved by a significant portion of the electric power generation industry in the relevant region, during the relevant period, as described in the immediate preceding sentence.
- 1.31. "Required Facility Documents" means all licenses, permits, authorizations, and agreements necessary for construction, operation, interconnection, and maintenance of the Facility including without limitation those set forth in Exhibit B.
- 1.32. "RPS Attributes" means all attributes related to the Net Output generated by the Facility that are required in order to provide PGE with "qualifying electricity," as that term is defined in Oregon's Renewable Portfolio Standard Act, Ore. Rev. Stat. 469A.010, in effect at the time of execution of this Agreement. RPS Attributes do not include Environmental Attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity and not needed to ensure that there are zero net emissions associated with the generation of electricity.
- 1.33. "Schedule" shall mean PGE Schedule 201 filed with the Oregon Public Utilities Commission ("Commission") in effect on the Effective Date of this Agreement and attached hereto as Exhibit D, the terms of which are hereby incorporated by reference.
- 1.34. "Senior Lien" means a prior lien which has precedence as to the property under the lien over another lien or encumbrance
- 1.35. "Start-Up Lost Energy Value" means for the period after the date specified in Section 2.2.2 but prior to achievement of the Commercial Operation Date: zero, unless the Net Output is less than the pro-rated Pre-Commercial Operation Date Minimum Net Output for the applicable delay period, and the time-weighted average of the delay period's Mid-C Index Price for On-Peak Hours and Off-Peak Hours is greater

than the time-weighted average of the delay period's Contract Price for On-Peak Hours and Off-Peak Hours, in which case Startup Lost Energy Value equals: (pro-rated Pre-Commercial Operation Date Minimum Net Output for the applicable period - Net Output for the applicable period) X (the lower of: the time-weighted average of the Contract Price for On-Peak hours and Off-Peak Hours during the applicable period; or (the time-weighted average of the Mid-C Index Price for On-Peak Hours and Off-Peak Hours during the applicable period – the time-weighted average of the Contract Price for On-Peak Hours and Off-Peak Hours during the applicable period)). The time-weighted average in this section will reflect the relative proportions of On-Peak Hours and Off-Peak Hours in each day.

- 1.36. "Start-Up Testing" means the completion of applicable required factory and start-up tests as set forth in Exhibit C.
- 1.37. "Step-in Rights" means the right of one party to assume an intervening position to satisfy all terms of an agreement in the event the other party fails to perform its obligations under the agreement.
- 1.38. "Term" shall mean the period beginning on the Effective Date and ending on the Termination Date.
- 1.39. "Test Period" shall mean a period of sixty (60) days or a commercially reasonable period determined by the Seller.
- 1.40. "Transmission Agreement" means an agreement executed by the Seller and the Transmission Provider(s) for Transmission Services.
- 1.41. "Transmission Curtailment" means a limitation on Seller's ability to deliver any portion of the scheduled energy to PGE due to the unavailability of transmission to the Point of Delivery (for any reason other than Force Majeure).
- 1.42. "Transmission Curtailment Replacement Energy Cost" means the greater of zero or the amount calculated as: ((Mid-C Index Price Contract Price) X curtailed energy) for periods of Transmission Curtailment.
- 1.43. "Transmission Provider(s)" means the signatory (other than the Seller) to the Transmission Agreement.
- 1.44. "Transmission Services" means any and all services (including but not limited to ancillary services and control area services) required for the firm transmission and delivery of Energy from the Facility to the Point of Delivery for a term not less than the Term of this Agreement.

References to Recitals, Sections, and Exhibits are to be the recitals, sections and exhibits of this Agreement.

SECTION 2: TERM; COMMERCIAL OPERATION DATE

2.1. This Agreement shall become effective upon execution by both Parties ("Effective Date").

- 2.2. Time is of the essence of this Agreement, and Seller's ability to meet certain requirements prior to the Commercial Operation Date and to complete all requirements to establish the Commercial Operation Date is critically important. Therefore,
 - 2.2.1. By 11/1/2019 Seller shall begin initial deliveries of Net Output; and
- 2.2.2. By <u>11/30/2019</u> Seller shall have completed all requirements under Section 1.5 and shall have established the Commercial Operation Date.
- 2.2.3. Unless the Parties agree in writing that a later Commercial Operation Date is reasonable and necessary, the Commercial Operation Date shall be no more than three (3) years from the Effective Date. PGE will not unreasonably withhold agreement to a Commercial Operation Date that is more than three (3) years from the Effective date if the Seller has demonstrated that a later Commercial Operation Date is reasonable and necessary.
- 2.3. This Agreement shall terminate on <u>18 years after effective date</u>, or the date the Agreement is terminated in accordance with Section 8 or 11, whichever is earlier ("Termination Date").

SECTION 3: REPRESENTATIONS AND WARRANTIES

- 3.1. Seller and PGE represent, covenant, and warrant as follows:
- 3.1.1. Seller warrants it is a <u>Limited liability company</u> duly organized under the laws of **Delaware**.
- 3.1.2. Seller warrants that the execution and delivery of this Agreement does not contravene any provision of, or constitute a default under, any indenture, mortgage, or other material agreement binding on Seller or any valid order of any court, or any regulatory agency or other body having authority to which Seller is subject.
- 3.1.3. Seller warrants that the Facility is and shall for the Term of this Agreement continue to be a "Qualifying Facility" ("QF") as that term is defined in the version of 18 C.F.R. Part 292 in effect on the Effective Date. Seller has provided the appropriate QF certification, which may include a Federal Energy Regulatory Commission ("FERC") self-certification to PGE prior to PGE's execution of this Agreement. At any time during the Term of this Agreement, PGE may require Seller to provide PGE with evidence satisfactory to PGE in its reasonable discretion that the Facility continues to qualify as a QF under all applicable requirements.
- 3.1.4. Seller warrants that it has not within the past two (2) years been the debtor in any bankruptcy proceeding, and Seller is and will continue to be for the Term of this Agreement current on all of its financial obligations.
- 3.1.5. Seller warrants that during the Term of this Agreement, all of Seller's right, title and interest in and to the Facility shall be free and clear of all liens and encumbrances other than liens and encumbrances arising from third-party financing of the Facility other than workers', mechanics', suppliers' or similar liens, or tax liens, in each case arising in the ordinary course of business that are either not yet due and

payable or that have been released by means of a performance bond acceptable to PGE posted within eight (8) calendar days of the commencement of any proceeding to foreclose the lien.

- 3.1.6. Seller warrants that it will design and operate the Facility consistent with Prudent Electrical Practices.
- 3.1.7. Seller warrants that the Facility has a Nameplate Capacity Rating not greater than 10,000 kW.
 - 3.1.8. Seller warrants that Net Dependable Capacity of the Facility is 10,000 kW.
- 3.1.9. Seller estimates that the average annual Net Output to be delivered by the Facility to PGE is <u>21,999,568</u> kilowatt-hours ("kWh"), which amount PGE will include in its resource planning.
- 3.1.10. Seller represents and warrants that the Facility shall achieve the following Mechanical Availability Percentages ("Guarantee of Mechanical Availability"):
- 3.1.10.1. Ninety percent (90%) beginning in the first Contract Year and extending through the Term for the Facility, if the Facility was operational and sold electricity to PGE or another buyer prior to the Effective Date of this Agreement; or
- 3.1.10.2. Ninety percent (90%) beginning in Contract Year three and extending throughout the remainder of the Term.
- 3.1.10.3. Annually, within 90 days of the end of each Contract Year, Seller shall send to PGE a detailed written report demonstrating and providing evidence of the actual MAP for the previous Contract Year.
- 3.1.10.4. Seller's failure to meet the Guarantee of Mechanical Availability in a Calendar Year shall result in damages payable to PGE by Seller equal to the Lost Energy Value. PGE shall bill Seller for such damages in accordance with Section 7.
- 3.1.11. Seller will deliver from the Facility to PGE at the Point of Delivery Net Output not to exceed a maximum of 33,750,000 kWh of Net Output during each Contract Year ("Maximum Net Output"). The cost of delivering energy from the Facility to PGE is the sole responsibility of the Seller.
- 3.1.12. By the Commercial Operation Date, Seller has entered into a Generation Interconnection Agreement for a term not less than the term of this Agreement.
- 3.1.13. PGE warrants that it has not within the past two (2) years been the debtor in any bankruptcy proceeding, and PGE is and will continue to be for the Term of this Agreement current on all of its financial obligations.
- 3.1.14. Seller warrants that the Facility satisfies the eligibility requirements specified in the Definition of a Small Cogeneration Facility or Small Power Production Facility Eligible to Receive the Standard Renewable Rates and Standard Renewable PPA in PGE's Schedule and Seller will not make any changes in its ownership, control or management during the term of this Agreement that would cause it to not be in compliance with the Definition of a Small Cogeneration Facility or Small Power

Production Facility Eligible to Receive the Standard Renewable Rates and Standard Renewable PPA in PGE's Schedule. Seller will provide, upon request by PGE not more frequently than every 36 months, such documentation and information as may be reasonably required to establish Seller's continued compliance with such Definition. PGE agrees to take reasonable steps to maintain the confidentiality of any portion of the above described documentation and information that the Seller identifies as confidential except PGE will provide all such confidential information to the Commission upon the Commission's request.

3.1.15. Seller warrants that it will comply with all requirements necessary for all Transferred RECs (as defined in Section 4.5) associated with Net Output to be issued, monitored, accounted for, and transferred by and through the Western Renewable Energy Generation System consistent with the provisions of OAR 330-160-0005 through OAR 330-160-0050. PGE warrants that it will reasonably cooperate in Seller's efforts to meet such requirements, including, for example serving as the qualified reporting entity for the Facility if the Facility is located in PGE's balancing authority.

SECTION 4: DELIVERY OF POWER, PRICE AND ENVIRONMENTAL ATTRIBUTES

- 4.1. Commencing on the Effective Date and continuing through the Term of this Agreement, Seller shall sell to PGE the entire Net Output delivered from the Facility at the Point of Delivery.
 - 4.2. PGE shall pay Seller the Contract Price for all delivered Net Output.
- 4.3. Upon completion of construction of the Facility, Seller shall provide PGE an As-built Supplement to specify the actual Facility as built. Seller shall not increase the Nameplate Capacity Rating above that specified in Exhibit A or increase the ability of the Facility to deliver Net Output in quantities in excess of the Net Dependable Capacity, or the Maximum Net Output as described in Section 3.1.11 above, through any means including, but not limited to, replacement, modification, or addition of existing equipment, except with prior written notice to PGE. In the event Seller increases the Nameplate Capacity Rating of the Facility to no more than 10,000 kW pursuant to this section, PGE shall pay the Contract Price for the additional delivered Net Output. In the event Seller increases the Nameplate Capacity Rating to greater than 10,000 kW, then Seller shall be required to enter into a new power purchase agreement for all delivered Net Output proportionally related to the increase of Nameplate Capacity above 10,000 kW.
- 4.4. Seller shall provide preschedules for all deliveries of energy hereunder, including identification of receiving and generating control areas, by 9:00:00 PPT on the last business day prior to the scheduled date of delivery. All energy shall be scheduled according to the most current North America Energy Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) scheduling rules and practices. The Parties' respective representatives shall maintain hourly real-time schedule coordination; provided, however, that in the absence of such coordination, the hourly schedule established by the exchange of preschedules shall be considered final. Seller and PGE shall maintain records of hourly energy schedules for accounting and

operating purposes. The final E-Tag shall be the controlling evidence of the Parties' schedule. All energy shall be prescheduled according to customary WECC scheduling practices. Seller shall make commercially reasonable efforts to schedule in any hour an amount equal to its expected Net Output for such hour. Seller shall maintain a minimum of two years records of Net Output and shall agree to allow PGE to have access to such records and to imbalance information kept by the Transmission Provider.

From the start of the Renewable Resource Deficiency Period through the remainder of the Term of this Agreement, Seller shall provide and PGE shall acquire the RPS Attributes for the Contract Years as specified in the Schedule and Seller shall retain ownership of all other Environmental Attributes (if any). During the Renewable Resource Sufficiency Period, Seller shall retain all Environmental Attributes in accordance with the Schedule. The Contract Price includes full payment for the Net Output and any RPS Attributes transferred to PGE under this Agreement. With respect to Environmental Attributes not transferred to PGE under this Agreement ("Seller-Retained Environmental Attributes") Seller may report under §1605(b) of the Energy Policy Act of 1992 or under any applicable program as belonging to Seller any of the Seller-Retained Environmental Attributes, and PGE shall not report under such program that such Seller-Retained Environmental Attributes belong to it. With respect to RPS Attributes transferred to PGE under this Agreement ("Transferred RECs"), PGE may report under §1605(b) of the Energy Policy Act of 1992 or under any applicable program as belonging to it any of the Transferred RECs, and Seller shall not report under such program that such Transferred RECs belong to it.

SECTION 5: OPERATION AND CONTROL

- 5.1. Seller shall operate and maintain the Facility in a safe manner in accordance with the Generation Interconnection Agreement, and Prudent Electrical Practices. PGE shall have no obligation to purchase Net Output from the Facility to the extent the interconnection of the Facility to PGE's electric system is disconnected, suspended or interrupted, in whole or in part, pursuant to the Generation Interconnection Agreement, or to the extent generation curtailment is required as a result of Seller's noncompliance with the Generation Interconnection Agreement. Seller is solely responsible for the operation and maintenance of the Facility. PGE shall not, by reason of its decision to inspect or not to inspect the Facility, or by any action or inaction taken with respect to any such inspection, assume or be held responsible for any liability or occurrence arising from the operation and maintenance by Seller of the Facility.
- 5.2. Seller agrees to provide sixty (60) days advance written notice of any scheduled maintenance that would require shut down of the Facility for any period of time.
- 5.3. If the Facility ceases operation for unscheduled maintenance, Seller immediately shall notify PGE of the necessity of such unscheduled maintenance, the time when such maintenance has occurred or will occur, and the anticipated duration of such maintenance. Seller shall take all reasonable measures and exercise its best

efforts to avoid unscheduled maintenance, to limit the duration of such unscheduled maintenance, and to perform unscheduled maintenance during Off-Peak hours.

SECTION 6: CREDITWORTHINESS

In the event Seller: a) is unable to represent or warrant as required by Section 3 that it has not been a debtor in any bankruptcy proceeding within the past two (2) years; b) becomes such a debtor during the Term; or c) is not or will not be current on all its financial obligations, Seller shall immediately notify PGE and shall promptly (and in no less than 10 days after notifying PGE) provide default security in an amount reasonably acceptable to PGE in one of the following forms: Senior Lien, Step-in Rights, a Cash Escrow or Letter of Credit. The amount of such default security that shall be acceptable to PGE shall be equal to: (annual On Peak Hours) X (On Peak Price – Off Peak Price) X (Net Dependable Capacity). Notwithstanding the foregoing, in the event Seller is not current on construction related financial obligations, Seller shall notify PGE of such delinquency and PGE may, in its discretion, grant an exception to the requirements to provide default security if the QF has negotiated financial arrangements with the construction loan lender that mitigate Seller's financial risk to PGE.

SECTION 7: BILLINGS, COMPUTATIONS AND PAYMENTS

- 7.1. On or before the thirtieth (30th) day following the end of each Billing Period, PGE shall send to Seller payment for Seller's deliveries of Net Output to PGE, together with computations supporting such payment. PGE may offset any such payment to reflect amounts owing from Seller to PGE pursuant to this Agreement and any other agreement related to the Facility between the Parties or otherwise. On or before the thirtieth (30th) day following the end of each Contract Year, PGE shall bill for any Lost Energy Value accrued pursuant to this Agreement.
- 7.2. Any amounts owing after the due date thereof shall bear interest at the Prime Rate plus two percent (2%) from the date due until paid; provided, however, that the interest rate shall at no time exceed the maximum rate allowed by applicable law.

SECTION 8: DEFAULT, REMEDIES AND TERMINATION

- 8.1. In addition to any other event that may constitute a default under this Agreement, the following events shall constitute defaults under this Agreement:
- 8.1.1. Breach by Seller or PGE of a representation or warranty, except for Section 3.1.4, set forth in this Agreement.
- 8.1.2. Seller's failure to provide default security, if required by Section 6, prior to delivery of any Net Output to PGE or within 10 days of notice.
- 8.1.3. Seller's failure to meet the Guarantee of Mechanical Availability established in Section 3.1.10 for two consecutive Contract Years or Seller's failure to provide any written report required by that section.
 - 8.1.4. If Seller is no longer a Qualifying Facility.
 - 8.1.5. Failure of PGE to make any required payment pursuant to Section 7.1.

- 8.1.6. Seller's failure to meet the Commercial Operation Date.
- 8.2. In the event of a default under Section 8.1.6, PGE may provide Seller with written notice of default. Seller shall have one year in which to cure the default during which time the Seller shall pay PGE damages equal to the Lost Energy Value. If Seller is unable to cure the default, PGE may immediately terminate this Agreement as provided in Section 8.3. PGE's resource sufficiency/deficiency position shall have no bearing on PGE's right to terminate the Agreement under this Section 8.2.
- 8.3. In the event of a default hereunder, except as otherwise provided in this Agreement, the non-defaulting party may immediately terminate this Agreement at its sole discretion by delivering written notice to the other Party. In addition, the non-defaulting Party may pursue any and all legal or equitable remedies provided by law or pursuant to this Agreement including damages related to the need to procure replacement power. A termination hereunder shall be effective upon the date of delivery of notice, as provided in Section 20. The rights provided in this Section 8 are cumulative such that the exercise of one or more rights shall not constitute a waiver of any other rights.
- 8.4. If this Agreement is terminated as provided in this Section 8, PGE shall make all payments, within thirty (30) days, that, pursuant to the terms of this Agreement, are owed to Seller as of the time of receipt of notice of default. PGE shall not be required to pay Seller for any Net Output delivered by Seller after such notice of default.
- 8.5. In the event PGE terminates this Agreement pursuant to this Section 8, and Seller wishes to again sell Net Output to PGE following such termination, PGE in its sole discretion may require that Seller shall do so subject to the terms of this Agreement, including but not limited to the Contract Price until the Term of this Agreement (as set forth in Section 2.3) would have run in due course had the Agreement remained in effect. At such time Seller and PGE agree to execute a written document ratifying the terms of this Agreement.
- 8.6. Sections 8.1, 8.4, 8.5, 10, and 19.2 shall survive termination of this Agreement.

SECTION 9: TRANSMISSION CURTAILMENTS

- 9.1. Seller shall give PGE notice as soon as reasonably practicable of any Transmission Curtailment that is likely to affect Seller's ability to deliver any portion of energy scheduled pursuant to Section 4.4 of this Agreement.
- 9.2. If as the result of a Transmission Curtailment, Seller does not deliver any portion of energy (including real-time adjustments), scheduled pursuant to Section 4.4 of this Agreement, Seller shall pay PGE the Transmission Curtailment Replacement Energy Cost for the number of MWh of energy reasonably determined by PGE as the difference between (i) the scheduled energy that would have been delivered to PGE under this Agreement during the period of Transmission Curtailment and (ii) the actual energy, if any, that was delivered to PGE for the period.

SECTION 10: INDEMNIFICATION AND LIABILITY

- 10.1. Seller agrees to defend, indemnify and hold harmless PGE, its directors, officers, agents, and representatives against and from any and all loss, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with Seller's delivery of electric power to PGE or with the facilities at or prior to the Point of Delivery, or otherwise arising out of this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PGE, Seller or others, excepting to the extent such loss, claim, action or suit may be caused by the negligence of PGE, its directors, officers, employees, agents or representatives.
- 10.2. PGE agrees to defend, indemnify and hold harmless Seller, its directors, officers, agents, and representatives against and from any and all loss, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with PGE's receipt of electric power from Seller or with the facilities at or after the Point of Delivery, or otherwise arising out of this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PGE, Seller or others, excepting to the extent such loss, claim, action or suit may be caused by the negligence of Seller, its directors, officers, employees, agents or representatives.
- 10.3. Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a Party to this Agreement. No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or to the public, nor affect the status of PGE as an independent public utility corporation or Seller as an independent individual or entity.
- 10.4. NEITHER PARTY SHALL BE LIABLE TO THE OTHER FOR SPECIAL, PUNITIVE, INDIRECT OR CONSEQUENTIAL DAMAGES, WHETHER ARISING FROM CONTRACT, TORT (INCLUDING NEGLIGENCE), STRICT LIABILITY OR OTHERWISE.

SECTION 11: INSURANCE

11.1. Prior to the connection of the Facility to PGE's electric system, provided such Facility has a design capacity of 200 kW or more, Seller shall secure and continuously carry for the Term hereof, with an insurance company or companies rated not lower than "B+" by the A. M. Best Company, insurance policies for bodily injury and property damage liability. Such insurance shall include provisions or endorsements naming PGE, it directors, officers and employees as additional insureds; provisions that such insurance is primary insurance with respect to the interest of PGE and that any insurance or self-insurance maintained by PGE is excess and not contributory insurance with the insurance required hereunder; a cross-liability or severability of

insurance interest clause; and provisions that such policies shall not be canceled or their limits of liability reduced without thirty (30) days' prior written notice to PGE. Initial limits of liability for all requirements under this section shall be \$1,000,000 million single limit, which limits may be required to be increased or decreased by PGE as PGE determines in its reasonable judgment economic conditions or claims experience may warrant.

- 11.2. Prior to the connection of the Facility to PGE's electric system, provided such facility has a design capacity of 200 kW or more, Seller shall secure and continuously carry for the Term hereof, in an insurance company or companies rated not lower than "B+" by the A. M. Best Company, insurance acceptable to PGE against property damage or destruction in an amount not less than the cost of replacement of the Facility. Seller promptly shall notify PGE of any loss or damage to the Facility. Unless the Parties agree otherwise, Seller shall repair or replace the damaged or destroyed Facility, or if the facility is destroyed or substantially destroyed, it may terminate this Agreement. Such termination shall be effective upon receipt by PGE of written notice from Seller. Seller shall waive its insurers' rights of subrogation against PGE regarding Facility property losses.
- 11.3. Prior to the connection of the Facility to PGE's electric system and at all other times such insurance policies are renewed or changed, Seller shall provide PGE with a copy of each insurance policy required under this Section, certified as a true copy by an authorized representative of the issuing insurance company or, at the discretion of PGE, in lieu thereof, a certificate in a form satisfactory to PGE certifying the issuance of such insurance. If Seller fails to provide PGE with copies of such currently effective insurance policies or certificates of insurance, PGE at its sole discretion and without limitation of other remedies, may upon ten (10) days advance written notice by certified or registered mail to Seller either withhold payments due Seller until PGE has received such documents, or purchase the satisfactory insurance and offset the cost of obtaining such insurance from subsequent power purchase payments under this Agreement.

SECTION 12: FORCE MAJEURE

12.1. As used in this Agreement, "Force Majeure" or "an event of Force Majeure" means any cause beyond the reasonable control of the Seller or of PGE which, despite the exercise of due diligence, such Party is unable to prevent or overcome. By way of example, Force Majeure may include but is not limited to acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes, and other labor disturbances, earthquakes, fires, lightning, epidemics, sabotage, restraint by court order or other delay or failure in the performance as a result of any action or inaction on behalf of a public authority which by the exercise of reasonable foresight such Party could not reasonably have been expected to avoid and by the exercise of due diligence, it shall be unable to overcome, subject, in each case, to the requirements of the first sentence of this paragraph. Force Majeure, however, specifically excludes the cost or availability of resources to operate the Facility, changes in market conditions that affect

the price of energy or transmission, wind or water droughts, and obligations for the payment of money when due.

- 12.2. If either Party is rendered wholly or in part unable to perform its obligation under this Agreement because of an event of Force Majeure, that Party shall be excused from whatever performance is affected by the event of Force Majeure to the extent and for the duration of the Force Majeure, after which such Party shall recommence performance of such obligation, provided that:
- 12.2.1. the non-performing Party, shall, promptly, but in any case within one (1) week after the occurrence of the Force Majeure, give the other Party written notice describing the particulars of the occurrence; and
- 12.2.2. the suspension of performance shall be of no greater scope and of no longer duration than is required by the Force Majeure; and
- 12.2.3. the non-performing Party uses its best efforts to remedy its inability to perform its obligations under this Agreement.
- 12.3. No obligations of either Party which arose before the Force Majeure causing the suspension of performance shall be excused as a result of the Force Majeure.
- 12.4. Neither Party shall be required to settle any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to the Party's best interests.

SECTION 13: SEVERAL OBLIGATIONS

Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership or joint venture or to impose a trust or partnership duty, obligation or liability between the Parties. If Seller includes two or more parties, each such party shall be jointly and severally liable for Seller's obligations under this Agreement.

SECTION 14: CHOICE OF LAW

This Agreement shall be interpreted and enforced in accordance with the laws of the state of Oregon, excluding any choice of law rules which may direct the application of the laws of another jurisdiction.

SECTION 15: PARTIAL INVALIDITY AND PURPA REPEAL

It is not the intention of the Parties to violate any laws governing the subject matter of this Agreement. If any of the terms of the Agreement are finally held or determined to be invalid, illegal or void as being contrary to any applicable law or public policy, all other terms of the Agreement shall remain in effect. If any terms are finally held or determined to be invalid, illegal or void, the Parties shall enter into negotiations concerning the terms affected by such decision for the purpose of achieving conformity with requirements of any applicable law and the intent of the Parties to this Agreement.

In the event the Public Utility Regulatory Policies Act (PURPA) is repealed, this Agreement shall not terminate prior to the Termination Date, unless such termination is mandated by state or federal law.

SECTION 16: WAIVER

Any waiver at any time by either Party of its rights with respect to a default under this Agreement or with respect to any other matters arising in connection with this Agreement must be in writing, and such waiver shall not be deemed a waiver with respect to any subsequent default or other matter.

SECTION 17: GOVERNMENTAL JURISDICTION AND AUTHORIZATIONS

This Agreement is subject to the jurisdiction of those governmental agencies having control over either Party or this Agreement. Seller shall at all times maintain in effect all local, state and federal licenses, permits and other approvals as then may be required by law for the construction, operation and maintenance of the Facility, and shall provide upon request copies of the same to PGE.

SECTION 18: SUCCESSORS AND ASSIGNS

This Agreement and all of the terms hereof shall be binding upon and inure to the benefit of the respective successors and assigns of the Parties. No assignment hereof by either Party shall become effective without the written consent of the other Party being first obtained and such consent shall not be unreasonably withheld. Notwithstanding the foregoing, either Party may assign this Agreement without the other Party's consent as part of (a) a sale of all or substantially all of the assigning Party's assets, or (b) a merger, consolidation or other reorganization of the assigning Party.

SECTION 19: ENTIRE AGREEMENT

- 19.1. This Agreement supersedes all prior agreements, proposals, representations, negotiations, discussions or letters, whether oral or in writing, regarding PGE's purchase of Net Output from the Facility. No modification of this Agreement shall be effective unless it is in writing and signed by both Parties.
- 19.2. By executing this Agreement, Seller releases PGE from any third party claims related to the Facility, known or unknown, which may have arisen prior to the Effective Date.

SECTION 20: NOTICES

20.1. All notices except as otherwise provided in this Agreement shall be in writing, shall be directed as follows and shall be considered delivered if delivered in person or when deposited in the U.S. Mail, postage prepaid by certified or registered mail and return receipt requested:

To Seller:

Blue Marmot V LLC c/o EDP Renewables North America LLC;

Attention: General Counsel 808 Travis, Suite 700 Houston, Texas 77002

To PGE:

Contracts Manager

QF Contracts, 3WTC0306 PGE - 121 SW Salmon St. Portland, Oregon 97204

20.2 The Parties may change the person to whom such notices are addressed, or their addresses, by providing written notices thereof in accordance with this Section 20.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed in their respective names as of the Effective Date.

PGE By: Name: Title: Date: **Blue Marmot V LLC** (Name Seller) By: Name: Fixecutive Vice President, Steve Irvin

Title: Canada Central Regions and Mexico

PGE Approved By: Business Terms Credit Legal Risk Mgt.

Date:

Brian Hayes Executive Vice President, **Asset Operations**

EXHIBIT A DESCRIPTION OF SELLER'S FACILITY

The facility will be a solar PV plant consisting of 38,715 polycrystalline modules of nominal 335W rating each. Total plant rating will be 12.97MWdc/10MWac.

Modules will be mounted to single-axis trackers.

Central inverter stations will be located at intermediate points in the PV field.

Modules will be evenly distributed to the inverter stations. The total inverter nameplate rating will be 10.0MWac. Each inverter will be directly coupled to a 34.5kV step-up transformer. The transformers will be connected to a 34.5kV AC collection system, which will feed into the plant switchgear.

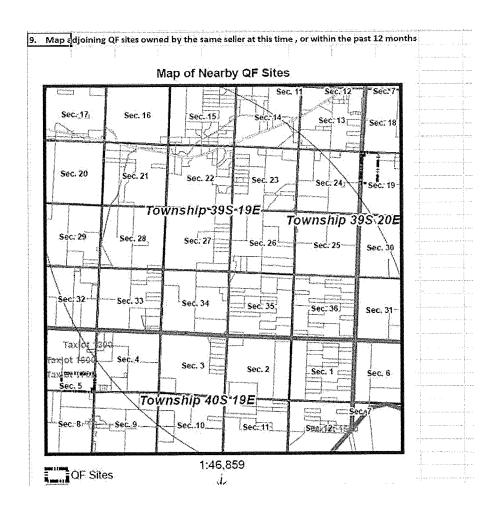
The plant switchgear will feed a 34.5kV transmission line, which will run overhead approximately 3.1 miles to the PacifiCorp Mile-Hi Substation.

Inside the Mile-Hi Substation, the transmission line will connect to a new bay containing a facility-owned 34.5kV/115kV GSU transformer, associated breakers, switching, bus, and controls.

The facility-owned components at Mile-Hi substation are considered part of the self-certified qualifying facility.

Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

id [/fwh] 2H 3H	4H 5	.н 6H		i,												- 1				- 1	
	4H 5	ы сы													*** ******	2.1					
2H 3H	4H :					ين أ		ar non				ieu .		17H 18H	+314	204	244	22H	2314	Total	
		H DH	્ર7#	, 6H	on.	128	124	123	12H 13	122	130	160	13	nr. 64	t .jan		0.	ກ້ະຕິເ	ואב	ŭ 918	
2	6 U	U.			D4			143	137	:53	151	147	59		6		n .	ň	ŏ · · · · ·	0 1201	
U	0. 0	. 0.	9		104	144	149							91	ñ	ň	ñ	n	o.		
			80											566	n	·····		0	ő		
U.	G u		101												45	n	ß	n	n.		
	0 0														79	0	0	n	n		
<u>V</u> .	U U:														70		···	ñ	n ·		
	B U	64													22	ň	0	0	ă		
U	0 0	3	1.35											40	ni.		0	0	ă ·	0 2940	6
<u>U</u>	<u>u</u> 0		65										64		<u></u>	· · · · Ř · · · · ·	ň		n	0 173	1
9	0 0	<u>V</u>												ň			0	ñ	ň.		
U.	0 0	U	V	ZU	33	110		100								n n	0.	n ·	Tr.	6 77	•
ū	G 0		On a	U.	55	21.		2575					1556	860	215				,	2 23987	, .
~2	~£ ~4.	209	304:																		
	0 0 0 0 0 0 0 0 0 0 0 0	0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0	0 0 0 3 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0	0 0 0 91 230 0 0 0 64 195 0 0 0 3 156 0 0 0 0 5 0 0 0 0 2 0 0 0 0 2 0 0 0 0 0	0 0 0 0 G S1 0 0 0 0 85 B83 0 0 0 5 51 B91 227 0 0 0 0 51 191 227 0 0 0 64 159 245 0 0 0 3 156 276 0 0 0 0 56 276 0 0 0 0 2 25 50 0 0 0 0 2 25 50 0 0 0 0 0 2 0 50	0 0 0 0 6 31 171 0 0 0 0 6 31 171 0 0 0 0 0 83 83 201 0 0 0 0 51 181 227 251 0 0 0 0 6 4 185 205 264 0 0 0 6 4 185 205 265 264 0 0 0 0 64 185 205 265 265 0 0 0 0 0 86 203 273 20 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0	0 0 0 0 G 31 171 183 0 0 0 0 G 31 171 183 0 0 0 0 0 83 88 200 20 20 0 0 0 0 0 51 191 227 251 260 0 0 0 0 51 191 227 251 260 0 0 0 0 64 155 205 254 261 268 0 0 0 0 3 136 276 231 261 261 0 0 0 0 86 200 20 20 20 20 0 0 0 0 0 0 2 105 200 200 0 0 0 0 0 0 2 105 200 200 0 0 0 0 0 0 0 0 55 57	0 0 0 0 6 31 171 183 20 0 0 0 0 83 188 201 276 279 0 0 0 51 181 227 251 260 268 0 0 0 0 51 181 227 251 260 268 0 0 0 64 195 245 254 268 276 0 0 0 64 195 245 254 268 276 0 0 0 0 3 186 276 231 234 283 0 0 0 0 86 203 233 237 238 0 0 0 0 0 2 55 200 205 195 0 0 0 0 0 0 2 55 200 205 115 0 0 0 0 0 0 0 0 55 30 113 117 0 0 0 0 0 0 0 55 37 38	0 0 0 0 6 31 171 183 20 195 2 0 0 0 0 0 83 184 201 266 279 252 0 0 0 5 1 181 227 251 280 288 261 262 0 0 0 5 1 181 227 251 280 288 261 262 0 0 0 6 4 155 265 264 264 266 276 265 0 0 0 0 64 155 265 264 264 268 276 265 0 0 0 0 3 156 276 261 264 263 262 0 0 0 0 86 203 233 237 268 232 0 0 0 0 0 0 2 155 200 205 155 232 0 0 0 0 0 0 0 2 155 200 205 155 232 0 0 0 0 0 0 0 0 0 0 0 5 39 115 117 117 0 0 0 0 0 0 0 0 0 5 39 39 30 10 117 117 0 0 0 0 0 0 0 0 0 0 0 0 5 39 39 38 102	0 0 0 0 6 31 171 183 180 185 186 0 0 0 0 0 83 184 201 216 279 221 226 2 0 0 0 0 51 181 227 251 260 268 251 247 261 261 261 279 261 261 261 261 261 261 261 261 261 261	0 0 0 0 6 31 171 183 120 195 186 706 0 0 0 0 83 189 201 216 279 24 226 223 0 0 0 0 51 181 227 251 260 268 254 247 242 26 26 26 26 26 26 26 26 26 26 26 26 26	0 0 0 0 6 31 1711 183 1820 195 195 196 706 105 0 0 0 0 83 183 201 286 279 221 228 223 279 0 0 0 0 51 181 227 251 260 268 251 247 242 244 0 0 0 0 0 51 181 227 251 260 268 251 247 242 244 0 0 0 0 0 64 189 205 268 251 271 274 267 268 263 262 0 0 0 0 64 189 205 261 268 276 265 257 258 243 0 0 0 0 0 86 200 273 247 254 256 255 257 258 243 0 0 0 0 0 86 200 273 237 238 231 230 233 232 0 0 0 0 0 0 0 86 200 273 237 238 231 230 233 232 0 0 0 0 0 0 0 2 05 200 205 195 132 191 318 189 0 0 0 0 0 0 0 0 0 0 0 0 55 200 205 195 132 191 138 139 0 0 0 0 0 0 0 0 0 0 0 55 200 257 258 253 102 301 134 100 0 0 0 0 0 0 0 0 55 200 257 258 259 102 301 124 100 134	0 0 0 0 0 6 31 171 183 120 195 186 700 105 173 0 0 0 0 0 0 83 188 201 216 219 21 221 221 221 221 221 221 221 221	0 0 0 0 6 31 171 183 120 185 186 700 105 173 132 0 0 0 0 0 0 0 83 184 201 126 279 127 227 228 128 120 120 120 120 120 120 120 120 120 120	0 0 0 0 0 0 0 1171 183 120 195 186 700 105 173 132 131 0 0 0 0 0 0 0 83 188 20 10 126 274 228 229 218 203 134 88 0 0 0 0 0 51 181 227 251 280 268 251 247 242 244 233 232 154 0 0 0 0 0 51 181 227 251 280 268 251 247 242 244 233 232 154 0 0 0 0 0 151 251 252 264 271 274 267 255 263 265 252 243 220 154 0 0 0 0 64 155 255 263 265 265 265 265 265 265 265 265 265 265	0 0 0 0 6 31 171 183 80 185 186 906 105 173 132 31 0 0 0 0 0 0 83 88 201 216 279 221 238 223 229 329 329 320 329 320 320 320 329 320 320 320 320 320 320 320 320 320 320	0 0 0 0 6 31 771 183 290 195 186 205 123 182 91 0 0 0 0 0 0 0 85 188 201 225 294 293 293 184 88 0 0 0 0 0 0 0 0 0 185 188 201 225 294 293 293 293 293 184 88 0 0 0 0 0 0 0 0 185 181 227 251 260 268 254 247 242 244 238 222 164 45 0 0 0 0 0 0 1 200 282 264 271 274 267 263 262 252 243 220 184 85 0 0 0 0 0 0 0 186 275 285 264 275 276 265 265 263 262 264 220 75 0 0 0 0 0 186 276 265 268 267 267 265 267 265 263 262 243 220 185 70 0 0 0 0 0 186 276 263 262 263 262 264 220 185 70 0 0 0 0 0 0 66 203 273 237 238 238 238 242 233 241 165 70 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0	0 0 0 0 6 31 771 183 200 195 186 206 207 123 123 23 19 10 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0	0 0 0 0 0 31 171 183 120 195 186 700 105 173 132 31 0 9 0 0 0 0 0 0 0 0 0 0 0 1 0 0 0 1 0	0 0 0 0 6 31 171 183 180 185 186 196 105 173 132 31 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0	0 0 0 0 0 31 171 183 290 195 186 206 105 173 122 91 0 0 0 0 0 0 0 173 174 183 190 195 186 206 105 173 122 91 0 0 0 0 0 0 0 0 0 173 174 175 175 175 175 175 175 175 175 175 175



FEDERAL ENERGY REGULATORY COMMISSION WASHINGTON, DC

OMB Control # 1902-0075 Expiration 06/30/2019

Form 556 Certification of Qualifying Facility (QF) Status for a Small Power Production or Cogeneration Facility

General

Questions about completing this form should be sent to Form556@ferc.gov. Information about the Commission's QF program, answers to frequently asked questions about QF requirements or completing this form, and contact information for QF program staff are available at the Commission's QF website, www.ferc.gov/QF. The Commission's QF website also provides links to the Commission's QF regulations (18 C.F.R. § 131.80 and Part 292), as well as other statutes and orders pertaining to the Commission's QF program.

Who Must File

Any applicant seeking QF status or recertification of QF status for a generating facility with a net power production capacity (as determined in lines 7a through 7g below) greater than 1000 kW must file a self-certification or an application for Commission certification of QF status, which includes a properly completed Form 556. Any applicant seeking QF status for a generating facility with a net power production capacity 1000 kW or less is exempt from the certification requirement, and is therefore not required to complete or file a Form 556. See 18 C.F.R. § 292.203.

How to Complete the Form 556

This form is intended to be completed by responding to the items in the order they are presented, according to the instructions given. If you need to back-track, you may need to clear certain responses before you will be allowed to change other responses made previously in the form. If you experience problems, click on the nearest help button () for assistance, or contact Commission staff at Form556@ferc.gov.

Certain lines in this form will be automatically calculated based on responses to previous lines, with the relevant formulas shown. You must respond to all of the previous lines within a section before the results of an automatically calculated field will be displayed. If you disagree with the results of any automatic calculation on this form, contact Commission staff at Form 556@ferc.gov to discuss the discrepancy before filing.

You must complete all lines in this form unless instructed otherwise. Do not alter this form or save this form in a different format. Incomplete or altered forms, or forms saved in formats other than PDF, will be rejected.

How to File a Completed Form 556

Applicants are required to file their Form 556 electronically through the Commission's eFiling website (see instructions on page 2). By filing electronically, you will reduce your filing burden, save paper resources, save postage or courier charges, help keep Commission expenses to a minimum, and receive a much faster confirmation (via an email containing the docket number assigned to your facility) that the Commission has received your filing.

If you are simultaneously filing both a waiver request and a Form 556 as part of an application for Commission certification, see the "Waiver Requests" section on page 3 for more information on how to file.

Paperwork Reduction Act Notice

This form is approved by the Office of Management and Budget. Compliance with the information requirements established by the FERC Form No. 556 is required to obtain or maintain status as a QF. See 18 C.F.R. § 131.80 and Part 292. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The estimated burden for completing the FERC Form No. 556, including gathering and reporting information, is as follows: 3 hours for self-certification of a small power production facility, 8 hours for self-certifications of a cogeneration facility, 6 hours for an application for Commission certification of a small power production facility, and 50 hours for an application for Commission certification of a cogeneration facility. Send comments regarding this burden estimate or any aspect of this collection of information, including suggestions for reducing this burden, to the following: Information Clearance Officer, Office of the Executive Director (ED-32), Federal Energy Regulatory Commission, 888 First Street N.E., Washington, DC 20426 (DataClearance@ferc.gov); and Desk Officer for FERC, Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (oira submission@omb.eop.gov). Include the Control No. 1902-0075 in any correspondence.

Electronic Filing (eFiling)

To electronically file your Form 556, visit the Commission's QF website at www.ferc.gov/QF and click the eFiling link.

If you are eFiling your first document, you will need to register with your name, email address, mailing address, and phone number. If you are registering on behalf of an employer, then you will also need to provide the employer name, alternate contact name, alternate contact phone number and and alternate contact email.

Once you are registered, log in to eFiling with your registered email address and the password that you created at registration. Follow the instructions. When prompted, select one of the following QF-related filing types, as appropriate, from the Electric or General filing category.

Filing category	Filing Type as listed in eFiling	Description
	(Fee) Application for Commission Cert. as Cogeneration QF	Use to submit an application for Commission certification or Commission recertification of a cogeneration facility as a QF.
	(Fee) Application for Commission Cert. as Small Power QF	Use to submit an application for Commission certification or Commission recertification of a small power production facility as a QF.
	Self-Certification Notice (QF, EG, FC)	Use to submit a notice of self- certification of your facility (cogeneration or small power production) as a QF.
Electric	Self-Recertification of Qualifying Facility (QF)	Use to submit a notice of self- recertification of your facility (cogeneration or small power production) as a QF.
	Supplemental Information or Request	Use to correct or supplement a Form 556 that was submitted with errors or omissions, or for which Commission staff has requested additional information. Do <i>not</i> use this filing type to report new changes to a facility or its ownership; rather, use a self-recertification or Commission recertification to report such changes.
General	(Fee) Petition for Declaratory Order (not under FPA Part 1)	Use to submit a petition for declaratory order granting a waiver of Commission QF regulations pursuant to 18 C.F.R. §§ 292.204(a) (3) and/or 292.205(c). A Form 556 is not required for a petition for declaratory order unless Commission recertification is being requested as part of the petition.

You will be prompted to submit your filing fee, if applicable, during the electronic submission process. Filing fees can be paid via electronic bank account debit or credit card.

During the eFiling process, you will be prompted to select your file(s) for upload from your computer.

Filing Fee

No filing fee is required if you are submitting a self-certification or self-recertification of your facility as a QF pursuant to 18 C.F.R. § 292.207(a).

A filing fee is required if you are filing either of the following:

- (1) an application for Commission certification or recertification of your facility as a QF pursuant to 18 C.F.R. § 292.207(b), or
- (2) a petition for declaratory order granting waiver pursuant to 18 C.F.R. §§ 292.204(a)(3) and/or 292.205(c).

The current fees for applications for Commission certifications and petitions for declaratory order can be found by visiting the Commission's QF website at www.ferc.gov/QF and clicking the Fee Schedule link.

You will be prompted to submit your filing fee, if applicable, during the electronic filing process described on page 2.

Required Notice to Utilities and State Regulatory Authorities

Pursuant to 18 C.F.R. § 292.207(a)(ii), you must provide a copy of your self-certification or request for Commission certification to the utilities with which the facility will interconnect and/or transact, as well as to the State regulatory authorities of the states in which your facility and those utilities reside. Links to information about the regulatory authorities in various states can be found by visiting the Commission's QF website at www.ferc.gov/QF and clicking the Notice Requirements link.

What to Expect From the Commission After You File

An applicant filing a Form 556 electronically will receive an email message acknowledging receipt of the filing and showing the docket number assigned to the filing. Such email is typically sent within one business day, but may be delayed pending confirmation by the Secretary of the Commission of the contents of the filing.

An applicant submitting a self-certification of QF status should expect to receive no documents from the Commission, other than the electronic acknowledgement of receipt described above. Consistent with its name, a self-certification is a certification by the applicant itself that the facility meets the relevant requirements for QF status, and does not involve a determination by the Commission as to the status of the facility. An acknowledgement of receipt of a self-certification, in particular, does not represent a determination by the Commission with regard to the QF status of the facility. An applicant self-certifying may, however, receive a rejection, revocation or deficiency letter if its application is found, during periodic compliance reviews, not to comply with the relevant requirements.

An applicant submitting a request for Commission certification will receive an order either granting or denying certification of QF status, or a letter requesting additional information or rejecting the application. Pursuant to 18 C.F.R. § 292.207(b)(3), the Commission must act on an application for Commission certification within 90 days of the later of the filing date of the application or the filing date of a supplement, amendment or other change to the application.

Waiver Requests

18 C.F.R. § 292.204(a)(3) allows an applicant to request a waiver to modify the method of calculation pursuant to 18 C.F.R. § 292.204(a)(2) to determine if two facilities are considered to be located at the same site, for good cause. 18 C.F.R. § 292.205(c) allows an applicant to request waiver of the requirements of 18 C.F.R. §§ 292.205(a) and (b) for operating and efficiency upon a showing that the facility will produce significant energy savings. A request for waiver of these requirements must be submitted as a petition for declaratory order, with the appropriate filing fee for a petition for declaratory order. Applicants requesting Commission recertification as part of a request for waiver of one of these requirements should electronically submit their completed Form 556 along with their petition for declaratory order, rather than filing their Form 556 as a separate request for Commission recertification. Only the filing fee for the petition for declaratory order must be paid to cover both the waiver request and the request for recertification if such requests are made simultaneously.

18 C.F.R. § 292.203(d)(2) allows an applicant to request a waiver of the Form 556 filing requirements, for good cause. Applicants filing a petition for declaratory order requesting a waiver under 18 C.F.R. § 292.203(d)(2) do not need to complete or submit a Form 556 with their petition.

Geographic Coordinates

If a street address does not exist for your facility, then line 3c of the Form 556 requires you to report your facility's geographic coordinates (latitude and longitude). Geographic coordinates may be obtained from several different sources. You can find links to online services that show latitude and longitude coordinates on online maps by visiting the Commission's QF webpage at www.ferc.gov/QF and clicking the Geographic Coordinates link. You may also be able to obtain your geographic coordinates from a GPS device, Google Earth (available free at https://earth.google.com), a property survey, various engineering or construction drawings, a property deed, or a municipal or county map showing property lines.

Filing Privileged Data or Critical Energy Infrastructure Information in a Form 556

The Commission's regulations provide procedures for applicants to either (1) request that any information submitted with a Form 556 be given privileged treatment because the information is exempt from the mandatory public disclosure requirements of the Freedom of Information Act, 5 U.S.C. § 552, and should be withheld from public disclosure; or (2) identify any documents containing critical energy infrastructure information (CEII) as defined in 18 C.F.R. § 388.113 that should not be made public.

If you are seeking privileged treatment or CEII status for any data in your Form 556, then you must follow the procedures in 18 C.F.R. § 388.112. See www.ferc.gov/help/filing-guide/file-ceii.asp for more information.

Among other things (see 18 C.F.R. § 388.112 for other requirements), applicants seeking privileged treatment or CEII status for data submitted in a Form 556 must prepare and file both (1) a complete version of the Form 556 (containing the privileged and/or CEII data), and (2) a public version of the Form 556 (with the privileged and/or CEII data redacted). Applicants preparing and filing these different versions of their Form 556 must indicate below the security designation of this version of their document. If you are *not* seeking privileged treatment or CEII status for any of your Form 556 data, then you should not respond to any of the items on this page.

Non-Public: Applicant is seeking privileged treatment and/or CEII status for data contained in the Form 556 lines indicated below. This non-public version of the applicant's Form 556 contains all data, including the data that is redacted in the (separate) public version of the applicant's Form 556.
 Public (redacted): Applicant is seeking privileged treatment and/or CEII status for data contained in the Form 556 lines indicated below. This public version of the applicants's Form 556 contains all data except for data from the lines indicated below, which has been redacted.
Privileged : Indicate below which lines of your form contain data for which you are seeking privileged treatment
Critical Energy Infrastructure Information (CEII): Indicate below which lines of your form contain data for which you are seeking CEII status

The eFiling process described on page 2 will allow you to identify which versions of the electronic documents you submit are public, privileged and/or CEII. The filenames for such documents should begin with "Public", "Priv", or "CEII", as applicable, to clearly indicate the security designation of the file. Both versions of the Form 556 should be unaltered PDF copies of the Form 556, as available for download from www.ferc.gov/QF. To redact data from the public copy of the submittal, simply omit the relevant data from the Form. For numerical fields, leave the redacted fields blank. For text fields, complete as much of the field as possible, and replace the redacted portions of the field with the word "REDACTED" in brackets. Be sure to identify above all fields which contain data for which you are seeking non-public status.

The Commission is not responsible for detecting or correcting filer errors, including those errors related to security designation. If your documents contain sensitive information, make sure they are filed using the proper security designation.

FEDERAL ENERGY REGULATORY COMMISSION WASHINGTON, DC

OMB Control # 1902-0075 Expiration 06/30/2019

Form 556 Certification of Qualifying Facility (QF) Status for a Small Power Production or Cogeneration Facility

1b Applicant stre 808 Travis	etaddress Street #700		
1c City		1d State/provi	ince
Houston		TX	
1e Postal code 77002	1f Country (if not United States)		1g Telephone number 713–265–0350
1h Has the instar	t facility ever previously been certified as a	QF? Yes ∑ N	No []
1i If yes, provide	the docket number of the last known QF fil	ing pertaining to t	his facility: QF16 - 1090 - 000
	ertification process is the applicant making		
Notice of se	lf-certification	Application for Co fee; see "Filing Fe	ommission certification (requires filing e" section on page 3)
QF status. A notice of self	of self-certification is a notice by the application does not establish of self-certification does not establish certification to verify compliance. See the age 3 for more information.	h a proceeding, an	d the Commission does not review a
	of QF status is the applicant seeking for its	acility? (check all t	hat apply)
Qualifying :	mall power production facility status	Qualifying cogen	eration facility status
1	rpose and expected effective date(s) of thi		
2	tification; facility expected to be installed b	In proceedings of the control of the	and to begin operation on
Change(s)	o a previously certified facility to be effecti	/e on 9/6/16	llangous section starting on page 10)
	pe(s) of change(s) below, and describe cha		naneous section starting on page 19)
_	nange and/or other administrative change in ownership	5)	
	(s) affecting plant equipment, fuel use, pov	ver production cap	acity and/or cogeneration thermal output
	or correction to a previous filing submitte		
	e supplement or correction in the Miscella		ing on page 19)
to the extent	following three statements is true, check the possible, explaining any special circumsta	nces in the Miscella	neous section starting on page 19.
☐ previous	nt facility complies with the Commission's y granted by the Commission in an order o the Miscellaneous section starting on page	ated	y virtue of a waiver of certain regulations (specify any other relevant waiver
The insta	nt facility would comply with the Commiss ntly with this application is granted	ion's QF requireme	ents if a petition for waiver submitted
☐ employn	nt facility complies with the Commission's tent of unique or innovative technologies in postration of compliance via this form diffic	ot contemplated b	by the structure of this form, that make

	2a Name of contact person			2b Telephone r	umber	
	Leslie A. Freiman			713-265-03	550	
	2c Which of the following describes	the contact person's relati	onship to the ap	plicant? (check on	e)	
		oyee, owner or partner of a				
no	Employee of a company affiliat					
ati	Lawyer, consultant, or other re					
Œ	2d Company or organization name				***********	ŧ
Į0	EDP Renewables North Ameri		2.7		and	
Contact Information	2e Street address (if same as Application		line 3a\⊠			
acı	Ze Street address (ii same as Applica	and, eneck nese and ship to	, mic 3d/[X]			
'nt						
ပိ	# 8 Cit		2g State/prov	inco		
	2f City		zg state/prov	IIICE		
		Total 196 111 21 1	(t-1)			
	2h Postal code	2i Country (if not United	States)			
					-	
_	3a Facility name				ļ.	
<u>.</u>	Blue Marmot V					
cat	3b Street address (if a street address	s does not exist for the fac	ility, check here a	and skip to line 3c		
Γ						
рc						-
Identification and Location	3c Geographic coordinates: If you in then you must specify the latitude the following formula to convert degrees + (minutes/60) + (second provided a street address for you	de and longitude coordina t to decimal degrees from nds/3600). See the "Geog	ates of the facility degrees, minute raphic Coordinat	r in degrees (to the s and seconds: de tes" section on pag	ree decimal places). Use ecimal degrees = ge 4 for help. If you	
tifi	East (+)	ar racincy in fine 35, then 3	pecifying the get	North (+)		
en	Longitude West (-)	0.412 degrees	Latitude	South (-) —	42.175 degrees	
	3d City (if unincorporated, check he	ere and enter nearest city)	☐ 3e State/p	province		
<u> </u>	Lakeview		Oregon			
Facility	3f County (or check here for indepe	endent city) 3	g Country (if no	t United States)		
ட	Lake	Necessary				
	Identify the electric utilities that are	contemplated to transact	with the facility.	- Alc. Sto.	And the second s	٦
S	4a Identify utility interconnecting v					1
itie	PacifiCorp (Pacific Pow					
T::	4b Identify utilities providing whee		if none			
g L	PacifiCorp (Pacific Pow		a none			
ij			ut or check here	if none		1
acı	4c Identify utilities purchasing the Portland General Electr		ut of theth here	II HOHE		
ns					w intown ntible source	-
Transacting Utilities	4d Identify utilities providing supplemental service or check here if none	lementary power, backup	power, maintena	ance power, and/o	ir interruptible power	
	PacifiCorp (Pacific Pow					

	defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or a holding cor 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(8)), and (utilities or holding companies, provide the percentage of equity interest in the facility direct owners hold at least 10 percent equity interest in the facility, then provide the two direct owners with the largest equity interest in the facility.	2) for owners which ty held by that own required information	are electric er. If no on for the
		Electric utility or holding company	If Yes, % equity interest
	Full legal names of direct owners	Yes No	100%
	1) Blue Marmot V LLC	Yes No [। <u></u> ।
	3)	Yes ☐ No ☐	ا] %
		Yes \ \ \ No \ \	,] %
		Yes \ \ \ No \ \	ا] %
		. Yes □ No □	,]
	6)	Yes No [}]
	8)	Yes No]
	9)	Yes No]
Operation	10)	Yes No]
and C	5b Upstream (i.e., indirect) ownership as of effective date or operation date: Identify all of the facility that both (1) hold at least 10 percent equity interest in the facility, and	(2) are electric utilit	ies, as
Ownersnip and C	of the facility that both (1) hold at least 10 percent equity interest in the facility, and defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or holding com 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(8)). Also equity interest in the facility held by such owners. (Note that, because upstream ov another, total percent equity interest reported may exceed 100 percent.) Check here if no such upstream owners exist.	(2) are electric utili panies, as defined i provide the percer vners may be subsic	ries, as n section ntage of
Ownersnip and O	of the facility that both (1) hold at least 10 percent equity interest in the facility, and defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or holding com 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(8)). Also equity interest in the facility held by such owners. (Note that, because upstream ov another, total percent equity interest reported may exceed 100 percent.) Check here if no such upstream owners exist. Full legal names of electric utility or holding company upstream owners.	(2) are electric utili panies, as defined i provide the percer vners may be subsic	n section stage of liaries of one % equity interest
Ownersnip and O	of the facility that both (1) hold at least 10 percent equity interest in the facility, and defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or holding com 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(8)). Also equity interest in the facility held by such owners. (Note that, because upstream ov another, total percent equity interest reported may exceed 100 percent.) Check here if no such upstream owners exist.	(2) are electric utili panies, as defined i provide the percer vners may be subsic	n section stage of liaries of one % equity interest
Ownersnip and O	of the facility that both (1) hold at least 10 percent equity interest in the facility, and defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or holding com 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(8)). Also equity interest in the facility held by such owners. (Note that, because upstream ov another, total percent equity interest reported may exceed 100 percent.) Check here if no such upstream owners exist. Full legal names of electric utility or holding company upstream ow 1) EDP Renewables North America LLC	(2) are electric utili panies, as defined i provide the percer vners may be subsic	n section stage of liaries of one % equity interest
Ownersnip and O	of the facility that both (1) hold at least 10 percent equity interest in the facility, and defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or holding com 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(8)). Also equity interest in the facility held by such owners. (Note that, because upstream ov another, total percent equity interest reported may exceed 100 percent.) Check here if no such upstream owners exist. Full legal names of electric utility or holding company upstream ow 1) EDP Renewables North America LLC	(2) are electric utili panies, as defined i provide the percer vners may be subsic	n section stage of liaries of one % equity interest
Ownersnip and O	of the facility that both (1) hold at least 10 percent equity interest in the facility, and defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or holding com 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(8)). Also equity interest in the facility held by such owners. (Note that, because upstream ov another, total percent equity interest reported may exceed 100 percent.) Check here if no such upstream owners exist. Full legal names of electric utility or holding company upstream ow 1) EDP Renewables North America LLC 2) 3)	(2) are electric utili panies, as defined i provide the percer vners may be subsic	n section stage of liaries of one % equity interest
Ownersnip and O	of the facility that both (1) hold at least 10 percent equity interest in the facility, and defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or holding com 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(8)). Also equity interest in the facility held by such owners. (Note that, because upstream ov another, total percent equity interest reported may exceed 100 percent.) Check here if no such upstream owners exist. Full legal names of electric utility or holding company upstream ow 1) EDP Renewables North America LLC 2) 3) 4)	(2) are electric utili panies, as defined i provide the percer vners may be subsic	n section stage of liaries of one % equity interest
Ownersnip and O	of the facility that both (1) hold at least 10 percent equity interest in the facility, and defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or holding com 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(8)). Also equity interest in the facility held by such owners. (Note that, because upstream ov another, total percent equity interest reported may exceed 100 percent.) Check here if no such upstream owners exist. Full legal names of electric utility or holding company upstream ow 1) EDP Renewables North America LLC 2) 3) 4)	(2) are electric utili panies, as defined i provide the percer vners may be subsic	n section ntage of liaries of one % equity
Ownersnip and O	of the facility that both (1) hold at least 10 percent equity interest in the facility, and defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or holding com 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(8)). Also equity interest in the facility held by such owners. (Note that, because upstream ov another, total percent equity interest reported may exceed 100 percent.) Check here if no such upstream owners exist. Full legal names of electric utility or holding company upstream ow 1) EDP Renewables North America LLC 2) 3) 4) 5) 6)	(2) are electric utili panies, as defined i provide the percer vners may be subsic	n section stage of liaries of one % equity interest
Ownersnip and O	of the facility that both (1) hold at least 10 percent equity interest in the facility, and defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or holding com 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(8)). Also equity interest in the facility held by such owners. (Note that, because upstream ow another, total percent equity interest reported may exceed 100 percent.) Check here if no such upstream owners exist. Full legal names of electric utility or holding company upstream ow 1) EDP Renewables North America LLC 2) 3) 4) 5) 6)	(2) are electric utili panies, as defined i provide the percer vners may be subsic	n section stage of liaries of one % equity interest
Ownersnip and O	of the facility that both (1) hold at least 10 percent equity interest in the facility, and defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or holding com 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(8)). Also equity interest in the facility held by such owners. (Note that, because upstream ov another, total percent equity interest reported may exceed 100 percent.) Check here if no such upstream owners exist. Full legal names of electric utility or holding company upstream ow 1) EDP Renewables North America LLC 2) 3) 4) 5) 6) 7) 8)	(2) are electric utili panies, as defined i provide the percer vners may be subsic	n section stage of liaries of one % equity interest

	6a	Describe the primary energy input: (check one main category and, if applicable, one subcategory)							
		Biomass (specify)	⊠ Ren	ewable resou	rces (specify)	☐ Geothe	ermal		
		☐ Landfill gas] Hydro pow	er - river	Fossil f	uel (specify	/)	
		☐ Manure digester gas] Hydro pow	er - tidal		Coal (not w	aste)	
] Hydro pow	er - wave	□ F	uel oil/die	sel	
		Sewage digester gas	Þ	Solar - phot	covoltaic		Natural gas	(not waste)	
		☐ Wood] Solar - theri	mal		Other fossil		
		☐ Other biomass (describe on p	age 19) [Wind			(describe o	n page 19)	
		☐ Waste (specify type below in line 6b) [Other renew (describe o	wable resource in page 19)	Other	(describe o	n page 19)	
	6b	If you specified "waste" as the primary o	energy input	in line 6a, ind	licate the type o	f waste fuel ι	used: (chec	k one)	
		Waste fuel listed in 18 C.F.R. § 292	.202(b) (spec	ify one of the	following)				
		☐ Anthracite culm produced p	rior to July	23, 1985	* :				
		\Box Anthracite refuse that has a ash content of 45 percent o		eat content of	6,000 Btu or les	s per pound a	and has an	average	
		Bituminous coal refuse that average ash content of 25 p			ent of 9,500 Btu	per pound o	r less and h	nas an	
nput		Top or bottom subbituminous coal produced on Federal lands or on Indian lands that has been determined to be waste by the United States Department of the Interior's Bureau of Land Management (BLM) or that is located on non-Federal or non-Indian lands outside of BLM's jurisdiction, provided that the applicant shows that the latter coal is an extension of that determined by BLM to be waste							
Energy Input	Coal refuse produced on Federal lands or on Indian lands that has been determined to be wast BLM or that is located on non- Federal or non-Indian lands outside of BLM's jurisdiction, providable applicant shows that the latter is an extension of that determined by BLM to be waste								
Ē	Lignite produced in association with the production of montan wax and lignite that becomes e								
		☐ Gaseous fuels (except natu	ral gas and s	ynthetic gas fi	rom coal) (descr	ibe on page	19)		
1 T. M. T. T		Waste natural gas from gas ☐ C.F.R. § 2.400 for waste nat compliance with 18 C.F.R. §	ural gas; incl i 2.400)	ude with your	filing any mate	rials necessai	ry to demo	nstrate	
		Materials that a government	nt agency ha	s certified for	disposal by com	bustion (des	scribe on p	age 19)	
		☐ Heat from exothermic reac	tions (descri	be on page 19	9)	Residual hea	t (describe	on page 19)	
		☐ Used rubber tires ☐	Plastic mat	erials	☐ Refinery of	ff-gas	☐ Petro	leum coke	
		Other waste energy input that hat hat facility industry (describe in the National lack of commercial value and exi	Miscellaneou stence in the	s section start absence of the	ing on page 19; ne qualifying fac	include a dis	cussion of	the fuel's	
	60	Provide the average energy input, calc energy inputs, and provide the related 292.202(j)). For any oil or natural gas f	l percentage	of the total a	verage annual e	nergy input 1	e following to the facili	g fossil fuel ty (18 C.F.R. §	
		Fuel		Annual average energy input for specified fuel		Percentage of total annual energy input			
		Natural gas		1	0 Btu/h		0 %		
		Oil-based fuels			0 Btu/h		0 %		
		Coal			0 Btu/h		0 %		

7g Maximum net power production capacity = 7a - 7f

Indicate the maximum gross and maximum net electric power production capacity of the facility at the point(s) of delivery by completing the worksheet below. Respond to all items. If any of the parasitic loads and/or losses identified in lines 7b through 7e are negligible, enter zero for those lines. 7a The maximum gross power production capacity at the terminals of the individual generator(s) under the most favorable anticipated design conditions 10,000 kW 7b Parasitic station power used at the facility to run equipment which is necessary and integral to the power production process (boiler feed pumps, fans/blowers, office or maintenance buildings directly related to the operation of the power generating facility, etc.). If this facility includes nonpower production processes (for instance, power consumed by a cogeneration facility's thermal host), do not include any power consumed by the non-power production activities in your reported parasitic station power. 5 kW 7c Electrical losses in interconnection transformers 176 kW 7d Electrical losses in AC/DC conversion equipment, if any 10 kW **7e** Other interconnection losses in power lines or facilities (other than transformers and AC/DC conversion equipment) between the terminals of the generator(s) and the point of interconnection 41 kW with the utility **7f** Total deductions from gross power production capacity = 7b + 7c + 7d + 7e232.0 kW

7h Description of facility and primary components: Describe the facility and its operation. Identify all boilers, heat recovery steam generators, prime movers (any mechanical equipment driving an electric generator), electrical generators, photovoltaic solar equipment, fuel cell equipment and/or other primary power generation equipment used in the facility. Descriptions of components should include (as applicable) specifications of the nominal capacities for mechanical output, electrical output, or steam generation of the identified equipment. For each piece of equipment identified, clearly indicate how many pieces of that type of equipment are included in the plant, and which components are normally operating or normally in standby mode. Provide a description of how the components operate as a system. Applicants for cogeneration facilities do not need to describe operations of systems that are clearly depicted on and easily understandable from a cogeneration facility's attached mass and heat balance diagram; however, such applicants should provide any necessary description needed to understand the sequential operation of the facility depicted in their mass and heat balance diagram. If additional space is needed, continue in the Miscellaneous section starting on page 19.

The facility will be a solar PV plant consisting of 38,715 polycrystalline modules of nominal 335W rating each. Total plant rating will be 12.97MWdc/10MWac. Modules will be mounted to single-axis trackers.

Central inverter stations will be located at intermediate points in the PV field. Modules will be evenly distributed to the inverter stations. The total inverter nameplate rating will be 10.0MWac. Each inverter will be directly coupled to a 34.5kV step-up transformer. The transformers will be connected to a 34.5kV AC collection system, which will feed into the plant switchgear.

The plant switchgear will feed a 34.5kV transmission line, which will run overhead approximately 3.1 miles to the PacifiCorp Mile-Hi Substation.

Inside the Mile-Hi Substation, the transmission line will connect to a new bay containing a facility-owned $34.5 \, kV/115 \, kV$ GSU transformer, associated breakers, switching, bus, and controls.

The facility-owned components at Mile-Hi substation are considered part of the self-certified qualifying facility.



9,768.0 kW

Information Required for Small Power Production Facility

If you indicated in line 1k that you are seeking qualifying small power production facility status for your facility, then you must respond to the items on this page. Otherwise, skip page 10.

must re	spond to the items on this page. Otherwise, skip page 10.	
	Pursuant to 18 C.F.R. § 292.204(a), the power production capacity of any small power production with the power production capacity of any other small power production facilities that use t resource, are owned by the same person(s) or its affiliates, and are located at the same site, r megawatts. To demonstrate compliance with this size limitation, or to demonstrate that you from this size limitation under the Solar, Wind, Waste, and Geothermal Power Production Ind (Pub. L. 101-575, 104 Stat. 2834 (1990) as amended by Pub. L. 102-46, 105 Stat. 249 (1991)), rethrough 8e below (as applicable).	he same energy nay not exceed 80 ur facility is exempt centives Act of 1990 espond to lines 8a
	8a Identify any facilities with electrical generating equipment located within 1 mile of the equipment of the instant facility, and for which any of the entities identified in lines 5a or 5b at least a 5 percent equity interest.	electrical generating , or their affiliates, holds
e l	Check here if no such facilities exist. 🔀	
olian	Facility location Root docket # (city or county, state) (if any) Common owner(s)	Maximum net power production capacity
atio	1) QF -	kW
을 <u>ដ</u>	2) QF -	kW
of Lir	3) QF -	kW
tification of Complial with Size Limitations	Check here and continue in the Miscellaneous section starting on page 19 if additional	space is needed
Certification of Compliance with Size Limitations	8b The Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990 (Incentives Act of 1990 (Incentives Act of 1990) (Incentives Act	ertified prior to 1995. Elncentives Act?
	before December 31, 1994? Yes No	
	8d Did construction of the facility commence on or before December 31, 1999? Yes	No []
	a brief narrative explanation in the Miscellaneous section starting on page 19 of the construction particular, describe why construction started so long after the facility was certified) and the toward completion of the facility.	answered Yes, provide action timeline (in diligence exercised
Certification of Compliance with Fuel Use Requirements	Pursuant to 18 C.F.R. § 292.204(b), qualifying small power production facilities may use foss amounts, for only the following purposes: ignition; start-up; testing; flame stabilization; cor prevention of unanticipated equipment outages; and alleviation or prevention of emergence the public health, safety, or welfare, which would result from electric power outages. The a used for these purposes may not exceed 25 percent of the total energy input of the facility period beginning with the date the facility first produces electric energy or any calendar year.	ntrol use; alleviation or cies, directly affecting mount of fossil fuels during the 12-month
ef C Rec	9a Certification of compliance with 18 C.F.R. § 292.204(b) with respect to uses of fossil fuel:	
on o Use	Applicant certifies that the facility will use fossil fuels <i>exclusively</i> for the purposes list	ted above.
Certificati with Fuel I	9b Certification of compliance with 18 C.F.R. § 292.204(b) with respect to amount of fossil f Applicant certifies that the amount of fossil fuel used at the facility will not, in aggre □ percent of the total energy input of the facility during the 12-month period beginni facility first produces electric energy or any calendar year thereafter.	egate, exceed 25

Information Required for Cogeneration Facility

If you indicated in line 1k that you are seeking qualifying cogeneration facility status for your facility, then you must respond to the items on pages 11 through 13. Otherwise skin pages 11 through 13.

to the i	, ,	13. Otherwise, skip pages 11 tillough 13.	l							
	Pursuant to 18 C.F.R. § 292.202(c), a cogeneration facility produces electric energy and forms of useful thermal energy (such as heat or steam) used for industrial, commercial, heating, or cooling purposes, through the sequent use of energy. Pursuant to 18 C.F.R. § 292.202(s), "sequential use" of energy means the following: (1) for a topping cycle cogeneration facility, the use of reject heat from a power production process in sufficient amounts in a thermal application or process to conform to the requirements of the operating standard contained in 18 C.F.R. § 292.205(a); or (2) for a bottoming-cycle cogeneration facility, the use of at least some reject heat from a thermal application or process for power production.									
	10a What type(s) of cog	eneration technology does the facility represent? (check all that apply)	-							
	Topping-cycle									
	other requirements balance diagram de meet certain requir	te the sequential operation of the cogeneration process, and to support compliance with a such as the operating and efficiency standards, include with your filing a mass and heat epicting average annual operating conditions. This diagram must include certain items and ements, as described below. You must check next to the description of each requirement t you have complied with these requirements.	- Control - Cont							
	Check to certify									
	compliance with indicated requirement	Requirement								
ation		Diagram must show orientation within system piping and/or ducts of all prime movers, heat recovery steam generators, boilers, electric generators, and condensers (as applicable), as well as any other primary equipment relevant to the cogeneration process.								
gener	,	Any average annual values required to be reported in lines 10b, 12a, 13a, 13b, 13d, 13f, 14a, 15b, 15d and/or 15f must be computed over the anticipated hours of operation.								
General Cogeneration Information		Diagram must specify all fuel inputs by fuel type and average annual rate in Btu/h. Fuel for supplementary firing should be specified separately and clearly labeled. All specifications of fuel inputs should use lower heating values.								
- Pue	900000000	Diagram must specify average gross electric output in kW or MW for each generator.								
Ğ		Diagram must specify average mechanical output (that is, any mechanical energy taken off of the shaft of the prime movers for purposes not directly related to electric power generation) in horsepower, if any. Typically, a cogeneration facility has no mechanical output.								
	Towns of the second of the sec	At each point for which working fluid flow conditions are required to be specified (see below), such flow condition data must include mass flow rate (in lb/h or kg/s), temperature (in °F, R, °C or K), absolute pressure (in psia or kPa) and enthalpy (in Btu/lb or kJ/kg). Exception: For systems where the working fluid is <i>liquid only</i> (no vapor at any point in the cycle) and where the type of liquid and specific heat of that liquid are clearly indicated on the diagram or in the Miscellaneous section starting on page 19, only mass flow rate and temperature (not pressure and enthalpy) need be specified. For reference, specific heat at standard conditions for pure liquid water is approximately 1.002 Btu/(lb*R) or 4.195 kJ/(kg*K).								
	manual ma	Diagram must specify working fluid flow conditions at input to and output from each steam turbine or other expansion turbine or back-pressure turbine.								
	jamentos c L	Diagram must specify working fluid flow conditions at delivery to and return from each thermal application.								
	P*************************************	Diagram must specify working fluid flow conditions at make-up water inputs.								

	EPAct 2005 cogeneration facilities: The Energy Policy Act of 2005 (EPAct 2005) established a new section 210(n) of the Public Utility Regulatory Policies Act of 1978 (PURPA), 16 USC 824a-3(n), with additional requirements for any qualifying cogeneration facility that (1) is seeking to sell electric energy pursuant to section 210 of PURPA and (2) was either not a cogeneration facility on August 8, 2005, or had not filed a self-certification or application for Commission certification of QF status on or before February 1, 2006. These requirements were implemented by the Commission in 18 C.F.R. § 292.205(d). Complete the lines below, carefully following the instructions, to demonstrate whether these additional requirements apply to your cogeneration facility and, if so, whether your facility complies with such requirements.	
	11a Was your facility operating as a qualifying cogeneration facility on or before August 8, 2005? Yes No	Ü
	11b Was the initial filing seeking certification of your facility (whether a notice of self-certification or an application for Commission certification) filed on or before February 1, 2006? Yes No	Ü
a .v	If the answer to either line 11a or 11b is Yes, then continue at line 11c below. Otherwise, if the answers to both lines 11a and 11b are No, skip to line 11e below.	
ntal Us acilitie	11c With respect to the design and operation of the facility, have any changes been implemented on or after February 2, 2006 that affect general plant operation, affect use of thermal output, and/or increase net power production capacity from the plant's capacity on February 1, 2006?	C
ner Fa	Yes (continue at line 11d below)	
Act 2005 Requirements for Fundamental Use Energy Output from Cogeneration Facilities	No. Your facility is not subject to the requirements of 18 C.F.R. § 292.205(d) at this time. However, it may be subject to to these requirements in the future if changes are made to the facility. At such time, the applicant would need to recertify the facility to determine eligibility. Skip lines 11d through 11j.	
for Fogen	11d Does the applicant contend that the changes identified in line 11c are not so significant as to make the facility a "new" cogeneration facility that would be subject to the 18 C.F.R. § 292.205(d) cogeneration requirements?	Ū
ments rom Co	Yes. Provide in the Miscellaneous section starting on page 19 a description of any relevant changes made to the facility (including the purpose of the changes) and a discussion of why the facility should not be considered a "new" cogeneration facility in light of these changes. Skip lines 11e through 11j.	
Require	No. Applicant stipulates to the fact that it is a "new" cogeneration facility (for purposes of determining the applicability of the requirements of 18 C.F.R. § 292.205(d)) by virtue of modifications to the facility that were initiated on or after February 2, 2006. Continue below at line 11e.	
)5 F / O	11e Will electric energy from the facility be sold pursuant to section 210 of PURPA?	
t 200 nergy	Yes. The facility is an EPAct 2005 cogeneration facility. You must demonstrate compliance with 18 C.F.R. § 292.205(d)(2) by continuing at line 11f below.	10000
EPAc of Er	No. Applicant certifies that energy will <i>not</i> be sold pursuant to section 210 of PURPA. Applicant also certifies its understanding that it must recertify its facility in order to determine compliance with the requirements of 18 C.F.R. § 292.205(d) <i>before</i> selling energy pursuant to section 210 of PURPA in the future. Skip lines 11f through 11j.	
	11f Is the net power production capacity of your cogeneration facility, as indicated in line 7g above, less than or equal to 5,000 kW?	C
	Yes, the net power production capacity is less than or equal to 5,000 kW. 18 C.F.R. § 292.205(d)(4) provides a rebuttable presumption that cogeneration facilities of 5,000 kW and smaller capacity comply with the requirements for fundamental use of the facility's energy output in 18 C.F.R. § 292.205(d)(2). Applicant certifies its understanding that, should the power production capacity of the facility increase above 5,000 kW, then the facility must be recertified to (among other things) demonstrate compliance with 18 C.F.R. § 292.205(d)(2). Skip lines 11g through 11j.	
	No, the net power production capacity is greater than 5,000 kW. Demonstrate compliance with the requirements for fundamental use of the facility's energy output in 18 C.F.R. § 292.205(d)(2) by continuing on the next page at line 11g.	

Lines 11g through 11k below guide the applicant through the process of demonstrating compliance with the requirements for "fundamental use" of the facility's energy output. 18 C.F.R. § 292.205(d)(2). Only respond to the lines on this page if the instructions on the previous page direct you to do so. Otherwise, skip this page.

18 C.F.R. § 292.205(d)(2) requires that the electrical, thermal, chemical and mechanical output of an EPAct 2005 cogeneration facility is used fundamentally for industrial, commercial, residential or institutional purposes and is not intended fundamentally for sale to an electric utility, taking into account technological, efficiency, economic, and variable thermal energy requirements, as well as state laws applicable to sales of electric energy from a qualifying facility to its host facility. If you were directed on the previous page to respond to the items on this page, then your facility is an EPAct 2005 cogeneration facility that is subject to this "fundamental use" requirement.

The Commission's regulations provide a two-pronged approach to demonstrating compliance with the requirements for fundamental use of the facility's energy output. First, the Commission has established in 18 C.F.R. § 292.205(d)(3) a "fundamental use test" that can be used to demonstrate compliance with 18 C.F.R. § 292.205(d)(2). Under the fundamental use test, a facility is considered to comply with 18 C.F.R. § 292.205(d)(2) if at least 50 percent of the facility's total annual energy output (including electrical, thermal, chemical and mechanical energy output) is used for industrial, commercial, residential or institutional purposes.

Second, an applicant for a facility that does not pass the fundamental use test may provide a narrative explanation of and support for its contention that the facility nonetheless meets the requirement that the electrical, thermal, chemical and mechanical output of an EPAct 2005 cogeneration facility is used fundamentally for industrial, commercial, residential or institutional purposes and is not intended fundamentally for sale to an electric utility, taking into account technological, efficiency, economic, and variable thermal energy requirements, as well as state laws applicable to sales of electric energy from a qualifying facility to its host facility.

Complete lines 11g through 11j below to determine compliance with the fundamental use test in 18 C.F.R. § 292.205(d)(3). Complete lines 11g through 11j even if you do not intend to rely upon the fundamental use test to demonstrate compliance with 18 C.F.R. § 292.205(d)(2).

11g Amount of electrical, thermal, chemical and mechanical energy output (net of internal generation plant losses and parasitic loads) expected to be used annually for industrial,		
commercial, residential or institutional purposes and not sold to an electric utility		MWh
11h Total amount of electrical, thermal, chemical and mechanical energy expected to be		
sold to an electric utility		MWh
11i Percentage of total annual energy output expected to be used for industrial, commercial, residential or institutional purposes and not sold to a utility		
= 100 * 11g /(11g + 11h)	0 '	%
11i Is the response in line 11i greater than or equal to 50 percent?		

11j Is the response in line 11i greater than or equal to 50 percent?

Yes. Your facility complies with 18 C.F.R. § 292.205(d)(2) by virtue of passing the fundamental use test provided in 18 C.F.R. § 292.205(d)(3). Applicant certifies its understanding that, if it is to rely upon passing the fundamental use test as a basis for complying with 18 C.F.R. § 292.205(d)(2), then the facility must comply with the fundamental use test both in the 12-month period beginning with the date the facility first produces electric energy, and in all subsequent calendar years.

No. Your facility does not pass the fundamental use test. Instead, you must provide in the Miscellaneous section starting on page 19 a narrative explanation of and support for why your facility meets the requirement that the electrical, thermal, chemical and mechanical output of an EPAct 2005 cogeneration facility is used fundamentally for industrial, commercial, residential or institutional purposes and is not intended fundamentally for sale to an electric utility, taking into account technological, efficiency, economic, and variable thermal energy requirements, as well as state laws applicable to sales of electric energy from a QF to its host facility. Applicants providing a narrative explanation of why their facility should be found to comply with 18 C.F.R. § 292.205(d)(2) in spite of non-compliance with the fundamental use test may want to review paragraphs 47 through 61 of Order No. 671 (accessible from the Commission's QF website at www.ferc.gov/QF), which provide discussion of the facts and circumstances that may support their explanation. Applicant should also note that the percentage reported above will establish the standard that that facility must comply with, both for the 12-month period beginning with the date the facility first produces electric energy, and in all subsequent calendar years. See Order No. 671 at paragraph 51. As such,

the applicant should make sure that it reports appropriate values on lines 11g and 11h above to serve as the

relevant annual standard, taking into account expected variations in production conditions.



attributable to use (net of

Usefulness of Topping-Cycle Thermal Output

Information Required for Topping-Cycle Cogeneration Facility

If you indicated in line 10a that your facility represents topping-cycle cogeneration technology, then you must respond to the items on pages 14 and 15. Otherwise, skip pages 14 and 15.

The thermal energy output of a topping-cycle cogeneration facility is the net energy made available to an industrial or commercial process or used in a heating or cooling application. Pursuant to sections 292.202(c), (d) and (h) of the Commission's regulations (18 C.F.R. §§ 292.202(c), (d) and (h)), the thermal energy output of a qualifying topping-cycle cogeneration facility must be useful. In connection with this requirement, describe the thermal output of the topping-cycle cogeneration facility by responding to lines 12a and 12b below.

12a Identify and describe each thermal host, and specify the annual average rate of thermal output made available

to each host for each use. For hosts with multiple uses of thermal output, provide the data for each use in separate rows.

Average annual rate of thermal output, provide the data for each use in separate rows.

	Name of entity (thermal host) taking thermal output	Thermal host's relationship to facility; Thermal host's use of thermal output	heat contained in process return or make-up water)
1)		Select thermal host's relationship to facility	
1)		Select thermal host's use of thermal output	Btu/h
2)		Select thermal host's relationship to facility	
2)		Select thermal host's use of thermal output	Btu/h
		Select thermal host's relationship to facility	
3)		Select thermal host's use of thermal output	Btu/h
4)		Select thermal host's relationship to facility	
4)		Select thermal host's use of thermal output	Btu/h
		Select thermal host's relationship to facility	
5)		Select thermal host's use of thermal output	Btu/h
		Select thermal host's relationship to facility	
6)		Select thermal host's use of thermal output	Btu/h

Check here and continue in the Miscellaneous section starting on page 19 if additional space is needed

12b Demonstration of usefulness of thermal output: At a minimum, provide a brief description of each use of the thermal output identified above. In some cases, this brief description is sufficient to demonstrate usefulness. However, if your facility's use of thermal output is not common, and/or if the usefulness of such thermal output is not reasonably clear, then you must provide additional details as necessary to demonstrate usefulness. Your application may be rejected and/or additional information may be required if an insufficient showing of usefulness is made. (Exception: If you have previously received a Commission certification approving a specific use of thermal output related to the instant facility, then you need only provide a brief description of that use and a reference by date and docket number to the order certifying your facility with the indicated use. Such exemption may not be used if any change creates a material deviation from the previously authorized use.) If additional space is needed, continue in the Miscellaneous section starting on page 19.

111 350	
Applicants for facilities representing topping-cycle technology must demonstrate comcycle operating standard and, if applicable, efficiency standard. Section 292.205(a)(1) or regulations (18 C.F.R. § 292.205(a)(1)) establishes the operating standard for topping-cycle useful thermal energy output must be no less than 5 percent of the total energy out (18 C.F.R. § 292.205(a)(2)) establishes the efficiency standard for topping-cycle cogener installation commenced on or after March 13, 1980: the useful power output of the fact thermal energy output must (A) be no less than 42.5 percent of the total energy input of facility; and (B) if the useful thermal energy output is less than 15 percent of the total energy be no less than 45 percent of the total energy input of natural gas and oil to the facility compliance with the topping-cycle operating and/or efficiency standards, or to demone exempt from the efficiency standard based on the date that installation commenced, re 13l below.	of the Commission's vole cogeneration facilities: tput. Section 292.205(a)(2) ation facilities for which ility plus one-half the useful of natural gas and oil to the nergy output of the facility, and the strate that your facility is espond to lines 13a through
If you indicated in line 10a that your facility represents <i>both</i> topping-cycle and bottom technology, then respond to lines 13a through 13l below considering only the energy attributable to the topping-cycle portion of your facility. Your mass and heat balance which mass and energy flow values and system components are for which portion (top cogeneration system.	inputs and outputs diagram must make clear
13a Indicate the annual average rate of useful thermal energy output made available	5. 4
to the host(s), net of any heat contained in condensate return or make-up water	Btu/h
13b Indicate the annual average rate of net electrical energy output	kW
13c Multiply line 13b by 3,412 to convert from kW to Btu/h	⊕ Btu/h
13d Indicate the annual average rate of mechanical energy output taken directly off of the shaft of a prime mover for purposes not directly related to power production (this value is usually zero)	qh
13e Multiply line 13d by 2,544 to convert from hp to Btu/h	
','	0 Btu/h
13f Indicate the annual average rate of energy input from natural gas and oil	Btu/h
13g Topping-cycle operating value = 100 * 13a / (13a + 13c + 13e)	0 %
13h Topping-cycle efficiency value = 100 * (0.5*13a + 13c + 13e) / 13f	0 %
13i Compliance with operating standard: Is the operating value shown in line 13g great	eater than or equal to 5%?
Yes (complies with operating standard) No (does not comply w	ith operating standard)
13j Did installation of the facility in its current form commence on or after March 13, 1	980?
Yes. Your facility is subject to the efficiency requirements of 18 C.F.R. § 292.20 compliance with the efficiency requirement by responding to line 13k or 13l, a	5(a)(2). Demonstrate as applicable, below.
No. Your facility is exempt from the efficiency standard. Skip lines 13k and 13	l.
13k Compliance with efficiency standard (for low operating value): If the operating v than 15%, then indicate below whether the efficiency value shown in line 13h greater	alue shown in line 13g is less than or equal to 45%:
Yes (complies with efficiency standard) No (does not comply w	ith efficiency standard)
13I Compliance with efficiency standard (for high operating value): If the operating value greater than or equal to 15%, then indicate below whether the efficiency value shown equal to 42.5%:	ralue shown in line 13g is in line 13h is greater than or
Yes (complies with efficiency standard) No (does not comply w	ith efficiency standard)

Usefulness of Bottoming-Cycle Thermal Output

Information Required for Bottoming-Cycle Cogeneration Facility

If you indicated in line 10a that your facility represents bottoming-cycle cogeneration technology, then you must respond to the items on pages 16 and 17. Otherwise, skip pages 16 and 17.

ems	ems on pages 16 and 17. Otherwise, skip pages 16 and 17.								
wh the	ich at least some of the reject heat Commission's regulations (18 C.F. le cogeneration facility must be us	oming-cycle cogeneration facility is the energy related is then used for power production. Pursuant to sect R. § 292.202(c) and (e)), the thermal energy output seful. In connection with this requirement, described for power production by responding to lines 14a and	tions 292.202(c) and (e) of of a qualifying bottoming- the process(es) from which						
148	14a Identify and describe each thermal host and each bottoming-cycle cogeneration process engaged in by each host. For hosts with multiple bottoming-cycle cogeneration processes, provide the data for each process <i>in</i>								
- Marian Paris	Name of entity (thermal host) performing the process from which at least some of the reject heat is used for power production	Thermal host's relationship to facility; Thermal host's process type	Has the energy input to the thermal host been augmented for purposes of increasing power production capacity? (if Yes, describe on p. 19)						
1)		Select thermal host's relationship to facility	Yes No						
Ľ		Select thermal host's process type							
2)		Select thermal host's relationship to facility	Yes No						
		Select thermal host's process type							
3)		Select thermal host's relationship to facility	Yes No						
		Select thermal host's process type							
	Check here and continue in the	he Miscellaneous section starting on page 19 if addi	tional space is needed						
ide fac mu ad pre fac to ch	14b Demonstration of usefulness of thermal output: At a minimum, provide a brief description of each process identified above. In some cases, this brief description is sufficient to demonstrate usefulness. However, if your facility's process is not common, and/or if the usefulness of such thermal output is not reasonably clear, then you must provide additional details as necessary to demonstrate usefulness. Your application may be rejected and/or additional information may be required if an insufficient showing of usefulness is made. (Exception: If you have previously received a Commission certification approving a specific bottoming-cycle process related to the instant facility, then you need only provide a brief description of that process and a reference by date and docket number to the order certifying your facility with the indicated process. Such exemption may not be used if any material changes to the process have been made.) If additional space is needed, continue in the Miscellaneous section starting on page 19.								
ľ									

than or equal to 45%:

Yes (complies with efficiency standard)

rm 556	cycle cogeneration admines
Applicants for facilities representing bottoming-cycle technology and for which installa March 13, 1990 must demonstrate compliance with the bottoming-cycle efficiency standard the Commission's regulations (18 C.F.R. § 292.205(b)) establishes the efficiency standard cogeneration facilities: the useful power output of the facility must be no less than 45 point of natural gas and oil for supplementary firing. To demonstrate compliance with the botstandard (if applicable), or to demonstrate that your facility is exempt from this standard installation of the facility began, respond to lines 15a through 15h below.	Idards. Section 292,205(b) of If for bottoming-cycle percent of the energy input ottoming-cycle efficiency Id based on the date that
If you indicated in line 10a that your facility represents <i>both</i> topping-cycle and bottomin technology, then respond to lines 15a through 15h below considering only the energy attributable to the bottoming-cycle portion of your facility. Your mass and heat balance which mass and energy flow values and system components are for which portion of the (topping or bottoming).	inputs and outputs e diagram must make clear
15a Did installation of the facility in its current form commence on or after March 13, 1 Yes. Your facility is subject to the efficiency requirement of 18 C.F.R. § 292.205(with the efficiency requirement by responding to lines 15b through 15h below No. Your facility is exempt from the efficiency standard. Skip the rest of page 1	b). Demonstrate compliance
15b Indicate the annual average rate of net electrical energy output	kW
15c Multiply line 15b by 3,412 to convert from kW to Btu/h	0 Btu/h
15d Indicate the annual average rate of mechanical energy output taken directly off of the shaft of a prime mover for purposes not directly related to power production (this value is usually zero)	hp
15e Multiply line 15d by 2,544 to convert from hp to Btu/h	0 Btu/h
15f Indicate the annual average rate of supplementary energy input from natural gas or oil	Btu/h
15g Bottoming-cycle efficiency value = 100 * (15c + 15e) / 15f	0 %

15h Compliance with efficiency standard: Indicate below whether the efficiency value shown in line 15g is greater

No (does not comply with efficiency standard)



Certificate of Completeness, Accuracy and Authority

Applicant must certify compliance with and understanding of filing requirements by checking next to each item below and signing at the bottom of this section. Forms with incomplete Certificates of Completeness, Accuracy and Authority will be rejected by the Secretary of the Commission.

Signer identified below certifies the follow	wing: (check all items and applicable subite	ems)						
He or she has read the filing, including mass and heat balance diagrams, an knows its contents.	ng any information contained in any attach d any information contained in the Miscella	ed documents, such as cogeneration aneous section starting on page 19, and						
to the best of his or her knowledge a								
He or she possess full power and aut Practice and Procedure (18 C.F.R. § 3	thority to sign the filing; as required by Rule 85.2005(a)(3)), he or she is one of the follow	e 2005(a)(3) of the Commission's Rules of wing: (check one)						
☐ The person on whose behalf	the filing is made							
oxtimes An officer of the corporation	officer of the corporation, trust, association, or other organized group on behalf of which the filing is made							
An officer, agent, or employed filing is made	e of the governmental authority, agency, o	r instrumentality on behalf of which the						
A representative qualified to Practice and Procedure (18 C	practice before the Commission under Ru L.F.R. § 385.2101) and who possesses autho	le 2101 of the Commission's Rules of ority to sign						
He or she has reviewed all automatic Miscellaneous section starting on pa	c calculations and agrees with their results, age 19.	unless otherwise noted in the						
interconnect and transact (see lines	s Form 556 and all attachments to the utilit 4a through 4d), as well as to the regulatory e the Required Notice to Public Utilities and	authorities of the states in which the						
Procedure (18 C.F.R. § 385,2005(c)) provi-	ature date below. Rule 2005(c) of the Com des that persons filing their documents ele filed documents. A person filing this docu vided below.	ctronically may use typed characters						
Your Signature	Your address	Date						
Leslie A. Freiman	808 Travis Street #700 Houston, TX 77002	9/6/2016						
Audit Notes								
Commission Staff Use Only:								

FERC Form 556 Page 19 - All Facilities

Miscellaneous

Use this space to provide any information for which there was not sufficient space in the previous sections of the form to provide. For each such item of information *clearly identify the line number that the information belongs to*. You may also use this space to provide any additional information you believe is relevant to the certification of your facility.

Your response below is not limited to one page. Additional page(s) will automatically be inserted into this form if the length of your response exceeds the space on this page. Use as many pages as you require.

Section 1(1) continued:

Blue Marmot V LLC (Applicant) hereby updates its prior self-certification of qualifying facility status to reflect an anticipated installation date of September 30, 2019 and commercial operation date of November 30, 2019. In addition, Applicant also updates the facility description and rating information provided in section 7.

EXHIBIT B REQUIRED FACILITY DOCUMENTS

Sellers Generation Interconnection Agreement

Transmission Service Agreement with PacifiCorp

Purchase option agreement

Conditional Use Permit issued by Lake County

Any additional permits that might be required by Lake County or Oregon Department of Environmental Quality, including access permit, building and electric permits, and storm water prevention permit

FERC Qualifying Facility self-certification

EXHIBIT C START-UP TESTING

VISUAL AND MECHANICAL INSPECTIONS

INVERTER COMMISSIONING

ELECTRICAL OPERATION TESTS

SYSTEM MONITORING VERIFICATION

TRACKER VERIFICATION

INFRARED SCANS

BLOCK TESTING

72-HOUR FUNCTIONAL TEST

GRID MATCH TEST

POWER CHARACTERIZATION

REVENUE METER VERIFICATION

REACTIVE POWER TEST

POWER OUTPUT TEST - PLANT PERFORMANCE AND ACCEPTANCE

EXHIBIT D SCHEDULE

SCHEDULE 201 QUALIFYING FACILITY 10 MW or LESS AVOIDED COST POWER PURCHASE INFORMATION

PURPOSE

To provide information about Standard Avoided Costs and Renewable Avoided Costs, Standard Power Purchase Agreements (PPA) and Negotiated PPAs, power purchase prices and price options for power delivered by a Qualifying Facility (QF) to the Company with nameplate capacity of 10,000 kW (10MW) or less.

AVAILABLE

To owners of QFs making sales of electricity to the Company in the State of Oregon (Seller).

APPLICABLE

For power purchased from small power production or cogeneration facilities that are QFs as defined in 18 Code of Federal Regulations (CFR) Section 292, that meet the eligibility requirements described herein and where the energy is delivered to the Company's system and made available for Company purchase pursuant to a Standard PPA.

ESTABLISHING CREDITWORTHINESS

The Seller must establish creditworthiness prior to service under this schedule. For a Standard PPA, a Seller may establish creditworthiness with a written acknowledgment that it is current on all existing debt obligations and that it was not a debtor in a bankruptcy proceeding within the preceding 24 months. If the Seller is not able to establish creditworthiness, the Seller must provide security deemed sufficient by the Company as set forth in the Standard PPA.

POWER PURCHASE INFORMATION

A Seller may call the Power Production Coordinator at (503) 464-8000 to obtain more information about being a Seller or how to apply for service under this schedule.

PPA

In accordance with terms set forth in this schedule and the Commission's Rules as applicable, the Company will purchase any Energy in excess of station service (power necessary to produce generation) and amounts attributable to conversion losses, which are made available from the Seller.

A Seller must execute a PPA with the Company prior to delivery of power to the Company. The agreement will have a term of up to 20 years as selected by the QF.

A QF with a nameplate capacity rating of 10 MW or less as defined herein may elect the option of a Standard PPA.

PPA (Continued)

Any Seller may elect to negotiate a PPA with the Company. Such negotiation will comply with the requirements of the Federal Energy Regulatory Commission (FERC), and the Commission including the guidelines in Order No. 07-360, and Schedule 202. Negotiations for power purchase pricing will be based on either the filed Standard Avoided Costs or Renewable Avoided Costs in effect at that time.

STANDARD PPA (Nameplate capacity of 10 MW or less)

A Seller choosing a Standard PPA will complete all informational and price option selection requirements in the applicable Standard PPA and submit the executed Agreement to the Company prior to service under this schedule. The Standard PPA is available at www.portlandgeneral.com. The available Standard PPAs are:

- Standard In-System Non-Variable Power Purchase Agreement
- Standard Off-System Non-Variable Power Purchase Agreement
- Standard In-System Variable Power Purchase Agreement
- Standard Off-System Variable Power Purchase Agreement
- Standard Renewable In-System Non-Variable Power Purchase Agreement
- Standard Renewable Off-System Non-Variable Power Purchase Agreement
- Standard Renewable In-System Variable Power Purchase Agreement
- Standard Renewable Off-System Variable Power Purchase Agreement

The Standard PPAs applicable to variable resources are available only to QFs utilizing wind, solar or run of river hydro as the primary motive force.

GUIDELINES FOR 10 MW OR LESS FACILITIES ELECTING STANDARD PPA

To execute the Standard PPA the Seller must complete all of the general project information requested in the applicable Standard PPA.

When all information required in the Standard PPA has been received in writing from the Seller, the Company will respond within 15 business days with a draft Standard PPA.

The Seller may request in writing that the Company prepare a final draft Standard PPA. The Company will respond to this request within 15 business days. In connection with such request, the QF must provide the Company with any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft Standard PPA.

When both parties are in full agreement as to all terms and conditions of the draft Standard PPA, the Company will prepare and forward to the Seller a final executable version of the agreement within 15 business days. Following the Company's execution, an executed copy will be returned to the Seller. Prices and other terms and conditions in the PPA will not be final and binding until the Standard PPA has been executed by both parties.

OFF-SYSTEM PPA

A Seller with a facility that interconnects with an electric system other than the Company's electric system may enter into a PPA with the Company after following the applicable Standard or Negotiated PPA guidelines and making the arrangements necessary for transmission of power to the Company's system.

BASIS FOR POWER PURCHASE PRICE

AVOIDED COST SUMMARY

The power purchase prices are based on either the Company's Standard Avoided Costs or Renewable Avoided Costs in effect at the time the agreement is executed. Avoided Costs are defined in 18 CFR 292.101(6) as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."

Monthly On-Peak prices are included in both the Standard Avoided Costs as listed in Tables 1a, 2a, and 3a and Renewable Avoided Costs as listed in Tables 4a, 5a, and 6a. Monthly Off-Peak prices are included in both the Standard Avoided Costs as listed in Tables 1b, 2b, and 3b and Renewable Avoided Costs as listed in Tables 4b, 5b, and 6b.

ON-PEAK PERIOD

The On-Peak period is 6:00 a.m. until 10:00 p.m., Monday through Saturday.

OFF-PEAK PERIOD

The Off-Peak period is 10:00 p.m. until 6:00 a.m., Monday through Saturday, and all day on Sunday.

Standard Avoided Costs are based on forward market price estimates through the Resource Sufficiency Period, the period of time during which the Company's Standard Avoided Costs are associated with incremental purchases of Energy and capacity from the market. For the Resource Deficiency Period, the Standard Avoided Costs reflect the fully allocated costs of a natural gas fueled combined cycle combustion turbine (CCCT) including fuel and capital costs. The CCCT Avoided Costs are based on the variable cost of Energy plus capitalized Energy costs at a 93% capacity factor based on a natural gas price forecast, with prices modified for shrinkage and transportation costs.

Renewable Avoided Costs are based on forward market price estimates through the Renewable Resource Sufficiency Period, the period of time during which the Company's Renewable Avoided Costs are associated with incremental purchases of energy and capacity from the market. For the Renewable Resource Deficiency Period, the Renewable Avoided Costs reflect the fully allocated costs of a wind plant including capital costs.

PRICING FOR STANDARD PPA

Pricing represents the purchase price per MWh the Company will pay for electricity delivered to a Point of Delivery (POD) within the Company's service territory pursuant to a Standard PPA up to the nameplate rating of the QF in any hour. Any Energy delivered in excess of the nameplate rating will be purchased at the applicable Off-Peak Prices for the selected pricing option.

The Standard PPA pricing will be based on either the Standard or Renewable Avoided Costs in effect at the time the agreement is executed.

The Company will pay the Seller either the Off-Peak Standard Avoided Cost pursuant to Tables 1b, 2b, or 3b or the Off-Peak Renewable Avoided Costs pursuant to Tables 4b, 5b, or 6b for: (a) all Net Output delivered prior to the Commercial Operation Date; (b) all Net Output deliveries greater than Maximum Net Output in any PPA year; (c) any generation subject to and as adjusted by the provisions of Section 4.3 of the Standard PPA; (d) Net Output delivered in the Off-Peak Period; and (e) deliveries above the nameplate capacity in any hour. The Company will pay the Seller either the On-Peak Standard Avoided Cost pursuant to Tables 1a, 2a, or 3a or the On-Peak Renewable Avoided Costs pursuant to Tables 4a, 5a, or 6a for all other Net Output. (See the PPA for defined terms.)

1) Standard Fixed Price Option

The Standard Fixed Price Option is based on Standard Avoided Costs including forecasted natural gas prices. It is available to all QFs.

This option is available for a maximum term of 15 years. Prices will be as established at the time the Standard PPA is executed and will be equal to the Standard Avoided Costs in Tables 1a and 1b, 2a and 2b, or 3a and 3c, depending on the type of QF, effective at execution. QFs using any resource type other than wind and solar are assumed to be Base Load QFs.

Prices paid to the Seller under the Standard Fixed Price Option include adjustments for the capacity contribution of the QF resource type relative to that of the avoided proxy resource. Both the Base Load QF resources (Tables 1a and 1b) and the avoided proxy resource, the basis used to determine Standard Avoided Costs for the Standard Fixed Price Option, are assumed to have a capacity contribution to peak of 100%. The capacity contribution for Wind QF resources (Tables 2a and 2b) is assumed to be 5%. The capacity contribution for Solar QF resources (Tables 3a and 3b) is assumed to be 5%.

Prices paid to the Seller under the Standard Fixed Price Option for Wind QFs (Tables 2a and 2b) include a reduction for the wind integration costs in Table 7. However, if the Wind QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the wind integration charges in Table 7, in addition to the prices listed in Tables 2a and 2b, for a net-zero effect.

Sheet No. 201-5

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

Sellers with PPAs exceeding 15 years will receive pricing equal to the Mid-C Index Price for all years up to five in excess of the initial 15.

	TABLE 1a											
'	Avoided Costs											
Standard Fixed Price Option for Base Load QF												
On-Peak Forecast (\$/MWH)												
	Year Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec											
Year	Jan	Feb	Mar	Apr	May	Jun		Aug 26.96	Sep 24.96	23.71	26.71	31.46
2016	28.21	22.46	15.61	14.71	12.46	16.96	23.96	30.96	29.46	27.71	28.71	33.71
2017	29.96	28.21	24.71	20.96	19.46	20.46	27.96 29.93	33.37	30.63	28.61	31.86	35.71
2018	31.71	31.11	28.11	22.13	21.28	21.28	31.67	35.08	33.37	31.38	32.52	38.21
2019	33.94	31.95	27.97	23.70	22.00	23.13		36.94	35.14	33.04	34.24	40.24
2020	35.74	33.64	29.45	24.95	23.15	24.35	33.34			65.48	68.60	68.72
2021	67.43	67.34	65.41	64.69	64.41	64.50	64.61	64.73 67.17	64.84 67.29	67.83	71.38	71.70
2022	69.01	68.84	68.08	67.13	66.81	66.91	67.04			70.12	73.56	73.70
2023	71.95	71.76	70.39	69.19	69.07	69.18	69.31	69.45	69.58	70.12	76.49	76.64
2024	74.17	73.85	72.67	71.29	71.10	71.21	71.35	71.50	71.63	75.80	82.57	82.89
2025	77.19	77.30	75.84	74.88	75.02	75.14	75.30	75.47	75.62		89.02	88.72
2026	85.18	85.30	82.77	81.28	81.22	81.36	81.56	81.74	81.90	82.36	91.39	91.15
2027	86.85	86.76	85.14	83.12	82.89	83.03	83.00	83.32	83.46	83.97		
2028	89.32	89.31	87.96	85.46	85.30	85.46	85.31	85.64	85.95	86.65	94.66	93.55
2029	94.06	93.99	91.23	88.74	87.97	88.15	87.71	88.06	88.61	89.34	98.37	98.11
2030	97.60	97.54	94.87	92.62	92.40	92.57	92.61	93.00	93.12	93.68	102.42	102.70
2031	99.56	99.50	96.78	94.48	94.26	94.43	94.47	94.87	94.99	95.56	104.47	104.76
2032	103.85	103.80	100.57	98.18	97.96	98.15	98.23	98.65	98.76	99.36	108.86 111.67	109.41 112.26
2033	106.56	106.51	103.17	100.72	100.50	100.69	100.78	101.21	101.32	101.93		114.96
2034	109.12	109.07	105.60	103.10	102.88	103.08	103.17	103.61	103.72	104.35	114.33	
2035	111.55	111.51	107.91	105.35	105.12	105.33	105.43	105.89	105.99	106.63	116.87	117.54
2036	113.85	113.80	110.14	107.53	107.30	107.51	107.60	108.07	108.18	108.83	119.27	119.95
2037	116.50	116.45	112.72	110.06	109.82	110.04	110.14	110.61	110.73	111.39	122.03	122.73
2038	119.08	119.03	115.22	112.51	112.27	112.49	112.59	113.08	113.19	113.87	124.71	125.42
2039	121.47	121.42	117.54	114.77	114.53	114.75	114.85	115.35	115.47	116.15	127.21	127.93
2040	124.25	124.20	120.25	117.43	117.18	117.41	117.51	118.02	118.14	118.84	130.10	130.85
2041	126.72	126.67	122.64	119.76	119.51	119.74	119.85	120.36	120.49	121.20	132.68	133.44

					TA	BLE 1b						
	Avoided Costs Standard Fixed Price Option for Base Load QF											
				O ₁	f-Peak Fo	orecast (\$/ WWH)		-			
			···			<u>-</u>						
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec 74
2016	25.61	20.71	13.96	11.41	6.31	10.11	15.71	20.96	20.96	21.21	23.46	26.71
2017	25.71	24.21	22.21	15.71	13.71	12.71	19.71	25.21	25.46	24.71	25.71	27.96
2018	26.17	28.12	25.56	19.46	14.68	12.54	19.71	27.04	26.93	25.35	28.20	30.62
2019	29.84	28.09	25.75	18.15	15.81	14.64	22.83	29.26	29.55	28.67	29.84	32.47
2020	31.75	29.88	27.38	19.28	16.79	15.54	24.27	31.12	31.43	30.50	31.75	34.55
2021	28.88	28.79	26.86	26.15	25.87	25.95	26.07	26.19	26.30	26.94	30.06	30.18
2022	29.73	29.56	28.79	27.85	27.53	27.63	27.75	27.88	28.00	28.54	32.09	32.42
2023	31.78	31.59	30.21	29.01	28.90	29.00	29.14	29.27	29.40	29.95	33.38	33.52
2024	33.48	33.16	31.98	30.60	30.41	30.52	30.66	30.81	30.95	31.51	35.80	35.96
2025	35.58	35.69	34.24	33.27	33.42	33.53	33.70	33.86	34.01	34.19	40.97	41.28
2026	42.77	42.89	40.36	38.87	38.81	38.95	39.15	39.34	39.50	39.95	46.62	46.31
2027	43.63	43.54	41.91	39.89	39.66	39.80	39.77	40.09	40.24	40.74	48.16	47.92
2028	45.26	45.25	43.90	41.40	41.23	41.40	41.25	41.58	41.89	42.59	50.60	49.48
2029	49.15	49.08	46.32	43.83	43.06	43.24	42.80	43.15	43.70	44.43	53.46	53.20
2030	51.82	51.76	49.09	46.84	46.62	46.79	46.83	47.22	47.34	47.90	56.64	56.92
2031	52.90	52.84	50.11	47.82	47.59	47.77	47.81	48.21	48.33	48.90	57.81	58.10
2032	56.59	56.54	53.31	50.92	50.70	50.89	50.97	51.39	51.50	52.10	61.60	62.15
2033	58.08	58.03	54.69	52.24	52.02	52.21	52.30	52.73	52.84	53.45	63.19	63.78
2034	59.54	59.50	56.03	53.52	53.30	53.50	53.59	54.04	54.15	54.77	64.76	65.39
2035	61.18	61.14	57.54	54.98	54.75	54.96	55.06	55.52	55.62	56.26	66.50	67.17
2036	62.67	62.62	58.96	56.35	56.12	56.33	56.43	56.89	57.00	57.65	68.09	68.78
2037	64.17	64.12	60.39	57.73	57.49	57.71	57.80	58.28	58.39	59.06	69.69	70.39
2038	65.73	65.69	61.88	59.17	58.93	59.15	59.25	59.73	59.85	60.52	71.37	72.08
2039	67.09	67.04	63.16	60.40	60.15	60.38	60.48	60.98	61.09	61.78	72.83	73.56
2040	68.83	68.78	64.83	62.01	61.76	61.99	62.09	62.60	62.72	63.42	74.68	75.42
2041	70.23	70.17	66.14	63.27	63.02	63.25	63.36	63.87	63.99	64.71	76.19	76.95

					TA	ABLE 2a						
	Avoided Costs											******
				Standard	Fixed Pr	ice Optic	on for Wi	nd QF				
				Oı	n-Peak Fe	orecast (\$/ NWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	24.37	18.62	11.77	10.87	8.62	13.12	20.12	23.12	21.12	19.87	22.87	27.62
2017	26.05	24.30	20.80	17.05	15.55	16.55	24.05	27.05	25.55	23.80	24.80	29.80
2018	27.72	27.12	24.12	18.14	17.29	17.29	25.94	29.38	26.64	24.62	27.87	31.72
2019	29.87	27.88	23.90	19.63	17.93	19.06	27.60	31.01	29.30	27.31	28.45	34.14
2020	31.59	29.49	25.30	20.80	19.00	20.20	29.19	32.79	30.99	28.89	30.09	36.09
2021	30.68	30.59	28.66	27.94	27.66	27.75	27.87	27.99	28.10	28.74	31.86	31.98
2022	31.56	31.39	30.62	29.68	29.36	29.46	29.59	29.72	29.84	30.38	33.93	34.25
2023	33.67	33.48	32.11	30.91	30.79	30.90	31.03	31.17	31.30	31.84	35.28	35.42
2024	35.38	35.06	33.88	32.49	32.30	32.42	32.56	32.70	32.84	33.40	37.70	37.85
2025	37.53	37.64	36.18	35.22	35.36	35.48	35.64	35.81	35.96	36.14	42.91	43.23
2026	44.75	44.87	42.35	40.86	40.79	40.94	41.13	41.32	41.48	41.94	48.60	48.29
2027	45.65	45.56	43.93	41.91	41.68	41.82	41.79	42.12	42.26	42.76	50.18	49.94
2028	47.32	47.31	45.96	43.46	43.30	43.46	43.31	43.64	43.95	44.65	52.66	51.55
2029	51.25	51.18	48.43	45.94	45.16	45.34	44.90	45.25	45.80	46.53	55.57	55.30
2030	53.96	53.90	51.23	48.98	48.76	48.93	48.97	49.36	49.48	50.04	58.78	59.06
2031	55.08	55.02	52.29	50.00	49.77	49.95	49.99	50.38	50.51	51.08	59.99	60.28
2032	58.77	58.72	55.49	53.10	52.88	53.07	53.15	53.57	53.68	54.28	63.78	64.33
2033	60.35	60.30	56.96	54.51	54.29	54.49	54.57	55.00	55.11	55.72	65.46	66.05
2034	61.88	61.83	58.36	55.86	55.63	55.84	55.93	56.37	56.48	57.10	67.09	67.72
2035	63.54	63.49	59.90	57.34	57.11	57.32	57.42	57.87	57.98	58.62	68.86	69.53
2036	65.04	65.00	61.33	58.72	58.49	58.70	58.80	59.27	59.38	60.03	70.46	71.15
2037	66.61	66.57	62.83	60.17	59.93	60.15	60.25	60.73	60.84	61.50	72.14	72.84
2038	68.23	68.18	64.37	61.66	61.42	61.64	61.74	62.23	62.34	63.02	73.86	74.57
2039	69.64	69.59	65.71	62.94	62.70	62.92	63.03	63.52	63.64	64.33	75.38	76.11
2040	71.42	71.37	67.41	64.60	64.35	64.58	64.68	65.18	65.30	66.00	77.27	78.01
2041	72.87	72.82	68.79	65.92	65.66	65.90	66.00	66.52	66.64	67.35	78.84	79.59

					ΤA	BLE 2b						
	Avoided Costs											
				Standard	Fixed Pr	ice Optic	n for Wi	nd QF				
				Of	f-Peak Fo	orecast (\$/ WWH)					
	:			1								
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	21.77	16.87	10.12	7.57	2.47	6.27	11.87	17.12	17.12	17.37	19.62	22.87
2017	21.80	20.30	18.30	11.80	9.80	8.80	15.80	21.30	21.55	20.80	21.80	24.05
2018	22.18	24.13	21.57	15.47	10.69	8.55	15.72	23.05	22.94	21.36	24.21	26.63
2019	25.77	24.02	21.68	14.08	11.74	10.57	18.76	25.19	25.48	24.60	25.77	28.40
2020	27.60	25.73	23.23	15.13	12.64	11.39	20.12	26.97	27.28	26.35	27.60	30.40
2021	24.65	24.56	22.63	21.92	21.64	21.72	21.84	21.96	22.07	22.71	25.83	25.95
2022	25.42	25.25	24.48	23.54	23.22	23.32	23.44	23.57	23.69	24.23	27.78	28.11
2023	27.39	27.20	25.82	24.62	24.51	24.61	24.75	24.88	25.01	25.56	28.99	29.13
2024	29.01	28.69	27.51	26.13	25.94	26.05	26.19	26.34	26.48	27.04	31.33	31.49
2025	31.02	31.13	29.68	28.71	28.86	28.97	29.14	29.30	29.45	29.63	36.41	36.72
2026	38.12	38.24	35.71	34.22	34.16	34.30	34.50	34.69	34.85	35.30	41.97	41.66
2027	38.89	38.80	37.17	35.15	34.92	35.06	35.03	35.35	35.50	36.00	43.42	43.18
2028	40.43	40.42	39.07	36.57	36.40	36.57	36.42	36.75	37.06	37.76	45.77	44.65
2029	44.23	44.16	41.40	38.91	38.14	38.32	37.88	38.23	38.78	39.51	48.54	48.28
2030	46.80	46.74	44.07	41.82	41.60	41.77	41.81	42.20	42.32	42.88	51.62	51.90
2031	47.78	47.72	44.99	42.70	42.47	42.65	42.69	43.09	43.21	43.78	52.69	52.98
2032	51.38	51.33	48.10	45.71	45.49	45.68	45.76	46.18	46.29	46.89	56.39	56.94
2033	52.77	52.72	49.38	46.93	46.71	46.90	46.99	47.42	47.53	48.14	57.88	58.47
2034	54.12	54.08	50.61	48.10	47.88	48.08	48.17	48.62	48.73	49.35	59.34	59.97
2035	55.66	55.62	52.02	49.46	49.23	49.44	49.54	50.00	50.10	50.74	60.98	61.65
2036	57.04	56.99	53.33	50.72	50.49	50.70	50.80	51.26	51.37	52.02	62.46	63.15
2037	58.43	58.38	54.65	51.99	51.75	51.97	52.06	52.54	52.65	53.32	63.95	64.65
2038	59.88	59.84	56.03	53.32	53.08	53.30	53.40	53.88	54.00	54.67	65.52	66.23
2039	61.13	61.08	57.20	54.44	54.19	54.42	54.52	55.02	55.13	55.82	66.87	67.60
2040	62.75	62.70	58.75	55.93	55.68	55.91	56.01	56.52	56.64	57.34	68.60	69.34
2041	64.04	63.98	59.95	57.08	56.83	57.06	57.17	57.68	57.80	58.52	70.00	70.76

					T/	BLE 3a						
	Avoided Costs											
	Standard Fixed Price Option for Solar QF											
	On-Peak Forecast (\$/MWH)											
I	1	F-4 [B6	A	Mov	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Year	Jan	Feb 22.46	Mar 15.61	Apr 14.71	May 12.46	16.96	23.96	26.96	24.96	23.71	26.71	31.46
2016	28.21 29.96	28.21	24.71	20.96	19.46	20.46	27.96	30.96	29.46	27.71	28.71	33.71
2017	31.71	31.11	28.11	22.13	21.28	21.28	29.93	33.37	30.63	28.61	31.86	35.71
2018	33.94	31.11	27.97	23.70	22.00	23.13	31.67	35.08	33.37	31.38	32.52	38.21
2019 2020	35.74	33.64	29.45	24.95	23.15	24.35	33.34	36.94	35.14	33.04	34.24	40.24
	33.98	33.89	31.96	31.24	30.96	31.05	31.16	31.28	31.39	32.03	35.15	35.27
2021 2022	34.92	34.75	33.98	33.04	32.72	32.82	32.94	33.08	33.20	33.74	37.28	37.61
2022	37.09	36.90	35.52	34.32	34.21	34.31	34.44	34.58	34.71	35.26	38.69	38.83
2023	38.86	38.54	37.36	35.98	35.79	35.90	36.04	36.19	36.32	36.88	41.18	41.33
2024	41.08	41.19	39.73	38.77	38.92	39.03	39.19	39.36	39.51	39.69	46.46	46.78
2026	48.37	48.49	45.97	44.48	44.42	44.56	44.75	44.94	45.10	45.56	52.22	51.91
2027	49.34	49.25	47.62	45.61	45.38	45.51	45.48	45.81	45.95	46.45	53.87	53.63
2028	51.08	51.07	49.72	47.22	47.06	47.22	47.07	47.40	47.72	48.41	56.42	55.31
2029	55.08	55.01	52.26	49.77	48.99	49.17	48.73	49.08	49.63	50.36	59.40	59.13
2030	57.87	57.81	55.14	52.89	52.67	52.84	52.88	53.27	53.39	53.95	62.69	62.97
2031	59.07	59.00	56.28	53.98	53.76	53.93	53.98	54.37	54.49	55.06	63.98	64.26
2032	62.83	62.78	59.56	57.16	56.94	57.13	57.21	57.64	57.75	58.34	67.85	68.39
2033	64.49	64.44	61.09	58.64	58.42	58.62	58.70	59.14	59.25	59.86	69.60	70.18
2034	66.10	66.05	62.58	60.08	59.85	60.05	60.14	60.59	60.70	61.32	71.31	71.94
2035	67.84	67.79	64.20	61.64	61.41	61.62	61.71	62.17	62.28	62.92	73.16	73.83
2036	69.43	69.38	65.72	63.11	62.88	63.09	63.19	63.66	63.77	64.42	74.85	75.54
2037	71.08	71.04	67.30	64.64	64.40	64.62	64.72	65.20	65.31	65.97	76.61	77.31
2038	72.78	72.73	68.93	66.22	65.98	66.20	66.30	66.78	66.90	67.57	78.42	79.13
2039	74.28	74.23	70.35	67.58	67.34	67.56	67.67	68.16	68.28	68.97	80.02	80.75
2040	76.15	76.10	72.15	69.33	69.08	69.31	69.42	69.92	70.04	70.74	82.01	82.75
2041	77.69	77.64	73.61	70.74	70.48	70.72	70.82	71.34	71.46	72.17	83.66	84.41

					T/	BLE 3b						
	Avoided Costs											
				Standard	Fixed P	rice Optic	on for So	lar QF				
				Of	f-Peak F	orecast (\$/MWH)					
			:			<u> </u>				i	NI	
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov 23.46	Dec 26.71
2016	25.61	20.71	13.96	11.41	6.31	10.11	15.71	20.96	20.96	21.21		
2017	25.71	24.21	22.21	15.71	13.71	12.71	19.71	25.21	25.46	24.71	25.71	27.96
2018	26.17	28.12	25.56	19.46	14.68	12.54	19.71	27.04	26.93	25.35	28.20	30.62
2019	29.84	28.09	25.75	18.15	15.81	14.64	22.83	29.26	29.55	28.67	29.84	32.47
2020	31.75	29.88	27.38	19.28	16.79	15.54	24.27	31.12	31.43	30.50	31.75	34.55
2021	28.88	28.79	26.86	26.15	25.87	25.95	26.07	26.19	26.30	26.94	30.06	30.18
2022	29.73	29.56	28.79	27.85	27.53	27.63	27.75	27.88	28.00	28.54	32.09	32.42
2023	31.78	31.59	30.21	29.01	28.90	29.00	29.14	29.27	29.40	29.95	33.38	33.52
2024	33.48	33.16	31.98	30.60	30.41	30.52	30.66	30.81	30.95	31.51	35.80	35.96
2025	35.58	35.69	34.24	33.27	33.42	33.53	33.70	33.86	34.01	34.19	40.97	41.28
2026	42.77	42.89	40.36	38.87	38.81	38.95	39.15	39.34	39.50	39.95	46.62	46.31
2027	43.63	43.54	41.91	39.89	39.66	39.80	39.77	40.09	40.24	40.74	48.16	47.92
2028	45.26	45.25	43.90	41.40	41.23	41.40	41.25	41.58	41.89	42.59	50.60	49.48
2029	49.15	49.08	46.32	43.83	43.06	43.24	42.80	43.15	43.70	44.43	53.46	53.20
2030	51.82	51.76	49.09	46.84	46.62	46.79	46.83	47.22	47.34	47.90	56.64	56.92
2031	52.90	52.84	50.11	47.82	47.59	47.77	47.81	48.21	48.33	48.90	57.81	58.10
2032	56.59	56.54	53.31	50.92	50.70	50.89	50.97	51.39	51.50	52.10	61.60	62.15
2033	58.08	58.03	54.69	52.24	52.02	52.21	52.30	52.73	52.84	53.45	63.19	63.78
2034	59.54	59.50	56.03	53.52	53.30	53.50	53.59	54.04	54.15	54.77	64.76	65.39
2035	61.18	61.14	57.54	54.98	54.75	54.96	55.06	55.52	55.62	56.26	66.50	67.17
2036	62.67	62.62	58.96	56.35	56.12	56.33	56.43	56.89	57.00	57.65	68.09	68.78
2037	64.17	64.12	60.39	57.73	57.49	57.71	57.80	58.28	58.39	59.06	69.69	70.39
2038	65.73	65.69	61.88	59.17	58.93	59.15	59.25	59.73	59.85	60.52	71.37	72.08
2039	67.09	67.04	63.16	60.40	60.15	60.38	60.48	60.98	61.09	61.78	72.83	73.56
2040	68.83	68.78	64.83	62.01	61.76	61.99	62.09	62.60	62.72	63.42	74.68	75.42
2041	70.23	70.17	66.14	63.27	63.02	63.25	63.36	63.87	63.99	64.71	76.19	76.95

PRICING OPTIONS FOR STANDARD PPA (Continued)

2) Renewable Fixed Price Option

The Renewable Fixed Price Option is based on Renewable Avoided Costs. It is available only to Renewable QFs that generate electricity from a renewable energy source that may be used by the Company to comply with the Oregon Renewable Portfolio Standard as set forth in ORS 469A.005 to 469A.210.

This option is available for a maximum term of 15 years. Prices will be as established at the time the Standard PPA is executed and will be equal to the Renewable Avoided Costs in Tables 4a and 4b, 5a and 5b, or 6a and 6b, depending on the type of QF, effective at execution. QFs using any resource type other than wind and solar are assumed to be Base Load QFs.

Sellers will retain all Environmental Attributes generated by the facility during the Renewable Resource Sufficiency Period. A Renewable QF choosing the Renewable Fixed Price Option must cede all RPS Attributes generated by the facility to the Company from the start of the Renewable Resource Deficiency Period through the remainder of the PPA term.

Prices paid to the Seller under the Renewable Fixed Price Option include adjustments for the capacity contribution of the QF resource type relative to that of the avoided proxy resource. Both Wind QF resources (Tables 5a and 5b) and the avoided proxy resource, the basis used to determine Renewable Avoided Costs for the Renewable Fixed Price Option, are assumed to have a capacity contribution to peak of 5%. The capacity contribution for Solar QF resources (Tables 6a and 6b) is assumed to be 5%. The capacity contribution for Base Load QF resources (Tables 4a and 4b) is assumed to be 100%.

The Renewable Avoided Costs during the Renewable Resource Deficiency Period reflect an increase for avoided wind integration costs, shown in Table 7.

Prices paid to the Seller under the Renewable Fixed Price Option for Wind QFs (Tables 5a and 5b) include a reduction for the wind integration costs in Table 7, which cancels out wind integration costs included in the Renewable Avoided Costs during the Renewable Resource Deficiency Period. However, if the Wind QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the wind integration charges in Table 7, in addition to the prices listed in Tables 5a and 5b.

Sellers with PPAs exceeding 15 years will receive pricing equal to the Mid-C Index Price for all years up to five in excess of the initial 15.

	TABLE 4a											
	Renewable Avoided Costs											
	Renewable Fixed Price Option for Base Load QF											
	On-Peak Forecast (\$/MWH)											
							·					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov 26.86	Dec 31.61
2016	28.36	22.61	15.76	14.86	12.61	17.11	24.11	27.11	25.11	23.86		
2017	30.11	28.36	24.86	21.11	19.61	20.61	28.11	31.11	29.61	27.86	28.86	33.86
2018	31.86	31.26	28.26	22.28	21.43	21.43	30.08	33.52	30.78	28.76	32.01	35.86
2019	34.10	32.11	28.13	23.86	22.16	23.29	31.83	35.24	33.53	31.54	32.68	38.37
2020	115.34	115.32	114.56	115.02	118.22	117.33	117.01	116.89	115.60	114.63	115.47	114.45
2021	117.94	118.18	116.67	117.75	120.59	119.83	119.26	119.77	118.26	117.25	118.55	117.22
2022	120.48	120.36	118.46	120.19	123.17	122.14	121.69	121.65	120.55	119.55	120.98	119.53
2023	123.26	122.83	120.85	122.92	125.37	124.64	124.29	123.92	123.08	121.92	123.63	122.53
2024	124.86	125.01	123.06	125.07	127.80	126.78	126.67	126.41	126.22	123.83	124.83	124.96
2025	127.73	128.05	125.86	128.21	131.66	130.48	129.53	129.66	128.84	126.59	127.76	127.41
2026	130.91	130.58	129.12	131.30	135.76	132.28	132.28	132.69	132.40	129.34	131.17	130.23
2027	133.47	133.03	131.38	133.50	139.48	134.88	134.51	135.95	134.79	131.96	133.26	132.78
2028	135.95	134.91	132.89	136.24	141.79	136.93	137.64	137.65	136.77	134.76	135.84	135.06
2029	138.81	138.57	135.91	139.29	149.30	140.74	140.82	140.82	140.86	137.50	138.32	138.21
2030	141.68	141.39	139.11	142.00	153.18	145.20	143.05	142.93	144.31	140.18	140.75	140.79
2031	144.29	143.79	142.17	145.52	156.10	149.27	145.71	146.65	146.86	143.04	144.15	143.71
2032	146.51	146.00	144.35	147.76	158.51	151.58	147.95	148.91	149.13	145.24	146.37	145.92
2033	149.91	149.40	147.71	151.19	162.18	155.09	151.39	152.37	152.59	148.62	149.77	149.31
2034	152.96	152.43	150.71	154.26	165.46	158.24	154.46	155.46	155.68	151.64	152.81	152.35
2035	155.76	155.22	153.46	157.08	168.50	161.14	157.29	158.31	158.54	154.41	155.60	155.13
2036	158.31	157.76	155.97	159.65	171.26	163.78	159.86	160.90	161.13	156.94	158.15	157.67
2037	161.83	161.27	159.44	163.20	175.07	167.42	163.42	164.48	164.71	160.43	161.67	161.18
2038	164.95	164.38	162.52	166.35	178.45	170.65	166.57	167.65	167.89	163.52	164.79	164.29
2039	168.13	167.55	165.66	169.56	181.89	173.94	169.79	170.89	171.13	166.68	167.97	167.46
2040	171.05	170.46	168.54	172.51	185.04	176.96	172.74	173.85	174.10	169.58	170.89	170.37
2040	174.69	174.08	172.11	176.17	188.98	180.72	176.40	177.55	177.80	173.18	174.52	173.99

TABLE 4b												
				R	enewable	e Avoided	l Costs					
			Ren	ewable F	ixed Pric	e Option	for Base	Load QI	=			
				0	ff-Peak F	orecast (\$/MWH)					
				-				-				
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	25.76	20.86	14.11	11.56	6.46	10.26	15.86	21.11	21.11	21.36	23.61	26.86
2017	25.86	24.36	22.36	15.86	13.86	12.86	19.86	25.36	25.61	24.86	25.86	28.11
2018	26.32	28.27	25.71	19.61	14.83	12.69	19.86	27.19	27.08	25.50	28.35	30.77
2019	30.00	28.25	25.91	18.31	15.97	14.80	22.99	29.42	29.71	28.83	30.00	32.63
2020	62.76	63.02	64.56	63.31	59.92	60.16	60.45	61.61	62.52	63.74	63.55	63.99
2021	64.93	64.15	65.85	64.48	61.58	61.62	62.27	62.62	63.78	65.82	63.38	65.09
2022	65.85	65.52	67.77	65.49	62.45	62.82	64.33	63.35	65.00	67.04	64.42	66.29
2023	66.70	66.75	69.10	67.28	62.84	64.01	65.40	64.85	66.14	68.41	65.38	67.63
2024	67.25	67.31	70.47	67.09	63.18	65.92	64.75	65.12	66.62	68.68	67.42	68.05
2025	68.62	68.60	71.94	68.08	63.17	66.28	66.12	67.12	67.23	70.19	69.68	69.06
2026	68.95	69.85	72.28	68.56	63.85	67.22	67.05	67.75	67.05	71.12	69.85	69.89
2027	71.31	71.29	73.13	70.34	63.69	68.45	68.79	68.16	68.57	73.22	70.67	71.18
2028	72.28	72.90	75.41	72.10	63.09	69.98	70.15	68.82	70.20	73.79	71.48	73.41
2029	72.78	73.60	76.79	73.50	58.25	70.29	71.37	70.00	71.53	74.58	73.61	74.68
2030	73.91	74.82	78.36	73.64	58.00	70.89	72.02	72.19	72.00	75.99	75.36	76.23
2031	75.51	76.70	79.40	74.00	59.17	70.67	73.55	73.71	72.16	77.24	77.07	76.31
2032	76.76	77.97	80.71	75.23	60.15	71.83	74.76	74.93	73.35	78.52	78.34	77.57
2033	78.46	79.69	82.50	76.89	61.48	73.42	76.42	76.58	74.97	80.25	80.07	79.29
2034	79.97	81.23	84.09	78.37	62.66	74.84	77.89	78.06	76.42	81.80	81.62	80.82
2035	81.52	82.80	85.71	79.88	63.87	76.28	79.39	79.57	77.89	83.38	83.19	82.38
2036	82.86	84.17	87.13	81.20	64.93	77.54	80.70	80.88	79.18	84.76	84.57	83.74
2037	84.69	86.03	89.05	83.00	66.36	79.25	82.49	82.67	80.93	86.63	86.44	85.59
2038	86.33	87.69	90.77	84.60	67.64	80.78	84.08	84.26	82.49	88.30	88.11	87.24
2039	87.99	89.38	92.52	86.23	68.95	82.34	85.70	85.89	84.08	90.01	89.81	88.92
2040	89.45	90.85	94.05	87.66	70.09	83.70	87.12	87.31	85.47	91.49	91.29	90.39
2041	91.42	92.86	96.13	89.59	71.63	85.55	89.04	89.24	87.36	93.51	93.31	92.39

					TA	ABLE 5a						
					enewable							-
			F		e Fixed F			ind QF				
	On-Peak Forecast (\$/MWH)											
			:			:						
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	24.52	18.77	11.92	11.02	8.77	13.27	20.27	23.27	21.27	20.02	23.02	27.77
2017	26.20	24.45	20.95	17.20	15.70	16.70	24.20	27.20	25.70	23.95	24.95	29.95
2018	27.87	27.27	24.27	18.29	17.44	17.44	26.09	29.53	26.79	24.77	28.02	31.87
2019	30.03	28.04	24.06	19.79	18.09	19.22	27.76	31.17	29.46	27.47	28.61	34.30
2020	75.38	75.37	74.61	75.06	78.26	77.37	77.05	76.93	75.64	74.67	75.51	74.49
2021	77.10	77.33	75.83	76.90	79.75	78.99	78.41	78.92	77.41	76.40	77.70	76.38
2022	78.85	78.72	76.82	78.56	81.53	80.51	80.05	80.02	78.92	77.92	79.34	77.90
2023	80.71	80.27	78.29	80.37	82.82	82.08	81.73	81.37	80.53	79.36	81.08	79.97
2024	81.74	81.89	79.93	81.95	84.68	83.66	83.55	83.28	83.10	80.71	81.71	81.84
2025	83.64	83.97	81.78	84.13	87.57	86.40	85.44	85.57	84.75	82.51	83.68	83.32
2026	85.97	85.64	84.18	86.37	90.82	87.34	87.34	87.75	87.46	84.40	86.23	85.29
2027	87.67	87.23	85.57	87.69	93.67	89.07	88.71	90.15	88.99	86.16	87.45	86.98
2028	89.26	88.22	86.20	89.55	95.10	90.24	90.95	90.96	90.08	88.07	89.15	88.37
2029	91.22	90.98	88.32	91.70	101.72	93.16	93.23	93.23	93.28	89.92	90.73	90.62
2030	93.17	92.88	90.60	93.49	104.67	96.69	94.54	94.42	95.80	91.67	92.24	92.28
2031	94.84	94.34	92.72	96.07	106.65	99.82	96.26	97.20	97.42	93.59	94.70	94.26
2032	96.40	95.90	94.24	97.65	108.40	101.47	97.85	98.80	99.02	95.13	96.26	95.82
2033	98.55	98.03	96.34	99.82	110.81	103.72	100.02	101.00	101.22	97.25	98.40	97.95
2034	100.44	99.91	98.19	101.74	112.94	105.72	101.94	102.94	103.17	99.12	100.29	99.83
2035	102.38	101.85	100.09	103.71	115.13	107.76	103.92	104.93	105.16	101.04	102.23	101.76
2036	104.06	103.51	101.72	105.40	117.01	109.53	105.61	106.65	106.88	102.69	103.90	103.42
2037	106.37	105.81	103.99	107.74	119.61	111.96	107.96	109.02	109.26	104.97	106.21	105.72
2038	108.42	107.86	105.99	109.82	121.92	114.12	110.05	111.12	111.37	107.00	108.26	107.76
2039	110.52	109.94	108.04	111.95	124.27	116.33	112.17	113.27	113.52	109.07	110.36	109.85
2040	112.32	111.73	109.81	113.77	126.31	118.23	114.00	115.12	115.37	110.85	112.16	111.64
2041	114.83	114.23	112.26	116.31	129.12	120.86	116.55	117.69	117.95	113.32	114.66	114.13

	TABLE 5b											
						e Avoided						
	Renewable Fixed Price Option for Wind QF											
	Off-Peak Forecast (\$/MWH)											
	:					1		A	Con	Oct	Nov	Dec
Year	Jan	Feb	Mar	Apr	May	Jun 6.42	Jul 12.02	Aug 17.27	Sep 17.27	17.52	19.77	23.02
2016	21.92	17.02	10.27	7.72	2.62		15.95	21.45	21.70	20.95	21.95	24.20
2017	21.95	20.45	18.45	11.95	9.95	8.95	15.87	23.20	23.09	21.51	24.36	26.78
2018	22.33	24.28	21.72	15.62	10.84	8.70		25.35	25.64	24.76	25.93	28.56
2019	25.93	24.18	21.84	14.24	11.90	10.73	18.92					59.84
2020	58.61	58.87	60.41	59.16	55.77	56.01	56.30	57.46	58.37	59.59	59.40	60.86
2021	60.70	59.92	61.62	60.25	57.35	57.39	58.04	58.39	59.55	61.59	59.15	
2022	61.54	61.21	63.46	61.18	58.14	58.51	60.02	59.04	60.69	62.73	60.11	61.98
2023	62.31	62.36	64.71	62.89	58.45	59.62	61.01	60.46	61.75	64.02	60.99	63.24
2024	62.78	62.84	66.00	62.62	58.71	61.45	60.28	60.65	62.15	64.21	62.95	63.58
2025	64.06	64.04	67.38	63.52	58.61	61.72	61.56	62.56	62.67	65.63	65.12	64.50
2026	64.30	65.20	67.63	63.91	59.20	62.57	62.40	63.10	62.40	66.47	65.20	65.24
2027	66.57	66.55	68.39	65.60	58.95	63.71	64.05	63.42	63.83	68.48	65.93	66.44
2028	67.45	68.07	70.58	67.27	58.26	65.15	65.32	63.99	65.37	68.96	66.65	68.58
2029	67.86	68.68	71.87	68.58	53.33	65.37	66.45	65.08	66.61	69.66	68.69	69.76
2030	68.89	69.80	73.34	68.62	52.98	65.87	67.00	67.17	66.98	70.97	70.34	71.21
2031	70.39	71.58	74.28	68.88	54.05	65.55	68.43	68.59	67.04	72.12	71.95	71.19
2032	71.55	72.76	75.50	70.02	54.94	66.62	69.55	69.72	68.14	73.31	73.13	72.36
2033	73.15	74.38	77.19	71.58	56.17	68.11	71.11	71.27	69.66	74.94	74.76	73.98
2034	74.55	75.81	78.67	72.95	57.24	69.42	72.47	72.64	71.00	76.38	76.20	75.40
2035	76.00	77.28	80.19	74.36	58.35	70.76	73.87	74.05	72.37	77.86	77.67	76.86
2036	77.23	78.54	81.50	75.57	59.30	71.91	75.07	75.25	73.55	79.13	78.94	78.11
2037	78.95	80.29	83.31	77.26	60.62	73.51	76.75	76.93	75.19	80.89	80.70	79.85
2038	80.48	81.84	84.92	78.75	61.79	74.93	78.23	78.41	76.64	82.45	82.26	81.39
2039	82.03	83.42	86.56	80.27	62.99	76.38	79.74	79.93	78.12	84.05	83.85	82.96
2040	83.37	84.77	87.97	81.58	64.01	77.62	81.04	81.23	79.39	85.41	85.21	84.31
2041	85.23	86.67	89.94	83.40	65.44	79.36	82.85	83.05	81.17	87.32	87.12	86.20

TABLE 6a												
					enewabl							
			F		e Fixed F			olar QF				
	On-Peak Forecast (\$/MWH)											
	-				D.E		1	A	Con	Oct	Nov	Dec
Year	Jan	Feb	Mar 45.70	Apr	May	Jun 17.11	Jul 24.11	Aug 27.11	Sep 25.11	23.86	26.86	31.61
2016	28.36	22.61	15.76	14.86	12.61			31.11	29.61	27.86	28.86	33.86
2017	30.11	28.36	24.86	21.11	19.61	20.61	28.11			28.76	32.01	35.86
2018	31.86	31.26	28.26	22.28	21.43	21.43	30.08	33.52	30.78 33.53	31.54	32.68	38.37
2019	34.10	32.11	28.13	23.86	22.16	23.29	31.83	35.24				
2020	78.62	78.60	77.84	78.30	81.50	80.60	80.29	80.17	78.88	77.91	78.74	77.73
2021	80.39	80.63	79.12	80.20	83.04	82.28	81.71	82.22	80.71	79.70	81.00	79.67
2022	82.21	82.08	80.18	81.92	84.89	83.87	83.41	83.38	82.27	81.27	82.70	81.25
2023	84.12	83.69	81.71	83.78	86.23	85.50	85.15	84.78	83.94	82.78	84.50	83.39
2024	85.22	85.37	83.41	85.43	88.16	87.14	87.03	86.76	86.58	84.19	85.19	85.32
2025	87.19	87.52	85.33	87.68	91.12	89.95	88.99	89.12	88.30	86.06	87.23	86.87
2026	89.59	89.26	87.80	89.99	94.44	90.96	90.96	91.37	91.08	88.02	89.85	88.91
2027	91.36	90.92	89.26	91.39	97.36	92.76	92.40	93.84	92.68	89.85	91.14	90.67
2028	93.02	91.98	89.96	93.31	98.86	94.00	94.71	94.72	93.84	91.84	92.91	92.13
2029	95.05	94.81	92.15	95.53	105.55	96.99	97.06	97.06	97.11	93.75	94.56	94.45
2030	97.08	96.79	94.51	97.40	108.58	100.60	98.45	98.33	99.71	95.58	96.15	96.19
2031	98.83	98.33	96.70	100.05	110.63	103.81	100.25	101.19	101.40	97.58	98.69	98.25
2032	100.47	99.96	98.30	101.71	112.47	105.53	101.91	102.87	103.08	99.20	100.32	99.88
2033	102.68	102.16	100.47	103.95	114.95	107.86	104.16	105.14	105.36	101.38	102.53	102.08
2034	104.66	104.13	102.41	105.96	117.16	109.94	106.16	107.16	107.38	103.34	104.51	104.05
2035	106.68	106.15	104.39	108.01	119.43	112.06	108.21	109.23	109.46	105.34	106.53	106.06
2036	108.44	107.90	106.11	109.79	121.40	113.91	110.00	111.04	111.27	107.08	108.29	107.81
2037	110.84	110.28	108.46	112.21	124.08	116.43	112.43	113.49	113.73	109.44	110.68	110.19
2038	112.98	112.41	110.55	114.38	126.47	118.68	114.60	115.68	115.92	111.55	112.82	112.32
2039	115.16	114.58	112.68	116.59	128.92	120.97	116.81	117.91	118.16	113.71	115.00	114.49
2040	117.06	116.47	114.54	118.51	131.04	122.96	118.74	119.86	120.11	115.58	116.89	116.37
2041	119.65	119.05	117.07	121.13	133.94	125.68	121.37	122.51	122.76	118.14	119.48	118.95

					T.A	BLE 6b						
						e Avoided						
			F				on for So	olar QF				
				Ot	ff-Peak F	orecast (\$/MWH)			:		
.,	•			A	Banca	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Year	Jan 25.70	Feb 20.86	Mar 14.11	Apr 11.56	May 6.46	10.26	15.86	21.11	21.11	21.36	23.61	26.86
2016 2017	25.76 25.86	24.36	22.36	15.86	13.86	12.86	19.86	25.36	25.61	24.86	25.86	28.11
2017	26.32	28.27	25.71	19.61	14.83	12.69	19.86	27.19	27.08	25.50	28.35	30.77
2019	30.00	28.25	25.91	18.31	15.97	14.80	22.99	29.42	29.71	28.83	30.00	32.63
2019	62.76	63.02	64.56	63.31	59.92	60.16	60.45	61.61	62.52	63.74	63.55	63.99
2020	64.93	64.15	65.85	64.48	61.58	61.62	62.27	62.62	63.78	65.82	63.38	65.09
2021	65.85	65.52	67.77	65.49	62.45	62.82	64.33	63.35	65.00	67.04	64.42	66.29
2023	66.70	66.75	69.10	67.28	62.84	64.01	65.40	64.85	66.14	68.41	65.38	67.63
2024	67.25	67.31	70.47	67.09	63.18	65.92	64.75	65.12	66.62	68.68	67.42	68.05
2025	68.62	68.60	71.94	68.08	63.17	66.28	66.12	67.12	67.23	70.19	69.68	69.06
2026	68.95	69.85	72.28	68.56	63.85	67.22	67.05	67.75	67.05	71.12	69.85	69.89
2027	71.31	71.29	73.13	70.34	63.69	68.45	68.79	68.16	68.57	73.22	70.67	71.18
2028	72.28	72.90	75.41	72.10	63.09	69.98	70.15	68.82	70.20	73.79	71.48	73.41
2029	72.78	73.60	76.79	73.50	58.25	70.29	71.37	70.00	71.53	74.58	73.61	74.68
2030	73.91	74.82	78.36	73.64	58.00	70.89	72.02	72.19	72.00	75.99	75.36	76.23
2031	75.51	76.70	79.40	74.00	59.17	70.67	73.55	73.71	72.16	77.24	77.07	76.31
2032	76.76	77.97	80.71	75.23	60.15	71.83	74.76	74.93	73.35	78.52	78.34	77.57
2033	78.46	79.69	82.50	76.89	61.48	73.42	76.42	76.58	74.97	80.25	80.07	79.29
2034	79.97	81.23	84.09	78.37	62.66	74.84	77.89	78.06	76.42	81.80	81.62	80.82
2035	81.52	82.80	85.71	79.88	63.87	76.28	79.39	79.57	77.89	83.38	83.19	82.38
2036	82.86	84.17	87.13	81.20	64.93	77.54	80.70	80.88	79.18	84.76	84.57	83.74
2037	84.69	86.03	89.05	83.00	66.36	79.25	82.49	82.67	80.93	86.63	86.44	85.59
2038	86.33	87.69	90.77	84.60	67.64	80.78	84.08	84.26	82.49	88.30	88.11	87.24
2039	87.99	89.38	92.52	86.23	68.95	82.34	85.70	85.89	84.08	90.01	89.81	88.92
2040	89.45	90.85	94.05	87.66	70.09	83.70	87.12	87.31	85.47	91.49	91.29	90.39
2041	91.42	92.86	96.13	89.59	71.63	85.55	89.04	89.24	87.36	93.51	93.31	92.39

WIND INTEGRATION

TABLE 7									
Wind Integration									
Year	Cost								
2015	3.77								
2016	3.84								
2017	3.91								
2018	3.99								
2019	4.07								
2020	4.15								
2021	4.23								
2022	4.31								
2023	4.39								
2024	4.47								
2025	4.56								
2026	4.65								
2027	4.74								
2028	4.83								
2029	4.92								
2030	5.02								
2031	5.12								
2032	5.21								
2033	5.31								
2034	5.42								
2035	5.52								
2036	5.63								
2037	5.74								
2038	5.85								
2039	5.96								
2040	6.08								

MONTHLY SERVICE CHARGE

Each separately metered QF not associated with a retail Customer account will be charged \$10.00 per month.

INSURANCE REQUIREMENTS

The following insurance requirements are applicable to Sellers with a Standard PPA:

- 1) QFs with nameplate capacity ratings greater than 200 kW are required to secure and maintain a prudent amount of general liability insurance. The Seller must certify to the Company that it is maintaining general liability insurance coverage for each QF at prudent amounts. A prudent amount will be deemed to mean liability insurance coverage for both bodily injury and property damage liability in the amount of not less than \$1,000,000 each occurrence combined single limit, which limits may be required to be increased or decreased by the Company as the Company determines in its reasonable judgment, that economic conditions or claims experience may warrant.
- Such insurance will include an endorsement naming the Company as an additional insured insofar as liability arising out of operations under this schedule and a provision that such liability policies will not be canceled or their limits reduced without 30 days' written notice to the Company. The Seller will furnish the Company with certificates of insurance together with the endorsements required herein. The Company will have the right to inspect the original policies of such insurance.
- 3) QFs with a design capacity of 200 kW or less are encouraged to pursue liability insurance on their own. The Oregon Public Utility Commission in Order No. 05-584 determined that it is inappropriate to require QFs that have a design capacity of 200 kW or less to obtain general liability insurance.

TRANSMISSION AGREEMENTS

If the QF is located outside the Company's service territory, the Seller is responsible for the transmission of power at its cost to the Company's service territory.

INTERCONNECTION REQUIREMENTS

Except as otherwise provided in a generation Interconnection Agreement between the Company and Seller, if the QF is located within the Company's service territory, switching equipment capable of isolating the QF from the Company's system will be accessible to the Company at all times. At the Company's option, the Company may operate the switching equipment described above if, in the sole opinion of the Company, continued operation of the QF in connection with the utility's system may create or contribute to a system emergency.

SCHEDULE 201 (Continued)

INTERCONNECTION REQUIREMENTS (Continued)

The QF owner interconnecting with the Company's distribution system must comply with all requirements for interconnection as established pursuant to Commission rule, in the Company's Rules and Regulations (Rule C) or the Company's Interconnection Procedures contained in its FERC Open Access Transmission Tariff (OATT), as applicable. The Seller will bear full responsibility for the installation and safe operation of the interconnection facilities.

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE PRICING UNDER THE STANDARD PPA

A QF will be eligible to receive pricing under the Standard PPA if the nameplate capacity of the QF, together with any other electric generating facility using the same motive force, owned or controlled by the Same Person(s) or Affiliated Person(s), and located at the Same Site, does not exceed 10 MW. A Community-Based or Family-Owned QF is exempt from these restrictions.

Definition of Community-Based

- a. A community project (or a community sponsored project) must have a recognized and established organization located within the county of the project or within 50 miles of the project that has a genuine role in helping the project be developed and must have some not insignificant continuing role with or interest in the project after it is completed and placed in service.
- b. After excluding the passive investor whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit, the equity (ownership) interests in a community sponsored project must be owned in substantial percentage (80 percent or more) by the following persons (individuals and entities): (i) the sponsoring organization, or its controlled affiliates; (ii) members of the sponsoring organization (if it is a membership organization) or owners of the sponsorship organization (if it is privately owned); (iii) persons who live in the county in which the project is located or who live a county adjoining the county in which the project is located; or (iv) units of local government, charities, or other established nonprofit organizations active either in the county in which the project is located or active in a county adjoining the county in which the project is located.

Definition of Family-Owned

After excluding the ownership interest of the passive investor whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit, five or fewer individuals own 50 percent or more of the equity of the project entity, or fifteen or fewer individuals own 90 percent or more of the project entity. A "look through" rule applies to closely held entities that hold the project entity, so that equity held by LLCs, trusts, estates, corporations, partnerships or other similar entities is considered held by the equity owners of the look through entity. An individual is a natural person. In counting to five or fifteen, spouses or children of an equity owner of the project owner who also have an equity interest are aggregated and counted as a single individual.

SCHEDULE 201 (Continued)

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE PRICING UNDER THE STANDARD PPA (Continued)

Definition of Person(s) or Affiliated Person(s)

As used above, the term "Same Person(s)" or "Affiliated Person(s)" means a natural person or persons or any legal entity or entities sharing common ownership, management or acting jointly or in concert with or exercising influence over the policies or actions of another person or entity. However, two facilities will not be held to be owned or controlled by the Same Person(s) or Affiliated Person(s) solely because they are developed by a single entity.

Furthermore, two facilities will not be held to be owned or controlled by the Same Person(s) or Affiliated Person(s) if such common person or persons is a "passive investor" whose ownership interest in the QF is primarily related to utilizing production tax credits, green tag values and MACRS depreciation as the primary ownership benefit and the facilities at issue are independent family-owned or community-based projects. A unit of Oregon local government may also be a "passive investor" in a community-based project if the local governmental unit demonstrates that it will not have an equity ownership interest in or exercise any control over the management of the QF and that its only interest is a share of the cash flow from the QF, which share will not exceed 20%. The 20% cash flow share limit may only be exceeded for good cause shown and only with the prior approval of the Commission.

Definition of Same Site

For purposes of the foregoing, generating facilities are considered to be located at the same site as the QF for which qualification for pricing under the Standard PPA is sought if they are located within a five-mile radius of any generating facilities or equipment providing fuel or motive force associated with the QF for which qualification for pricing under the Standard PPA is sought.

Definition of Shared Interconnection and Infrastructure

QFs otherwise meeting the above-described separate ownership test and thereby qualified for entitlement to pricing under the Standard PPA will not be disqualified by utilizing an interconnection or other infrastructure not providing motive force or fuel that is shared with other QFs qualifying for pricing under the Standard PPA so long as the use of the shared interconnection complies with the interconnecting utility's safety and reliability standards, interconnection agreement requirements and Prudent Electrical Practices as that term is defined in the interconnecting utility's approved Standard PPA.

OTHER DEFINITIONS

Mid-C Index Price

As used in this schedule, the daily Mid-C Index Price shall be the Day Ahead Intercontinental Exchange ("ICE") for the bilateral OTC market for energy at the Mid-C Physical for Average

SCHEDULE 201 (Continued)

OTHER DEFINITIONS (Continued)

On-Peak Power and Average Off-Peak Power found on the following website: https://www.theice.com/products/OTC/Physical-Energy/Electricity. In the event ICE no longer publishes this index, PGE and the Seller agree to select an alternative successor index representative of the Mid-C trading hub.

Definition of RPS Attributes

As used in this schedule, RPS Attributes means all attributes related to the Net Output generated by the Facility that are required in order to provide PGE with "qualifying electricity," as that term is defined in Oregon's Renewable Portfolio Standard Act, Ore. Rev. Stat. 469A.010, in effect at the time of execution of this Agreement. RPS Attributes do not include Environmental Attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity and not needed to ensure that there are zero net emissions associated with the generation of electricity.

Definition of Environmental Attributes

As used in this schedule, Environmental Attributes shall mean any and all claims, credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical, or other substance to the air, soil or water. Environmental Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil, or water such as (subject to the foregoing) sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; and (2) any avoided emissions of carbon dioxide (CO2), methane (CH4), and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere.

Definition of Resource Sufficiency Period

This is the period from the current year through 2020.

Definition of Resource Deficiency Period

This is the period from 2021 through 2034.

Definition of Renewable Resource Sufficiency Period

This is the period from the current year through 2019.

Definition of Renewable Resource Deficiency Period

This is the period from 2020 through 2034.

SCHEDULE 201 (Concluded)

DISPUTE RESOLUTION

Upon request, the QF will provide the purchasing utility with documentation verifying the ownership, management and financial structure of the QF in reasonably sufficient detail to allow the utility to make an initial determination of whether or not the QF meets the above-described criteria for entitlement to pricing under the Standard PPA.

The QF may present disputes to the Commission for resolution using the following process:

The QF may file a complaint asking the Commission to adjudicate disputes regarding the formation of the standard contract. The QF may not file such a complaint during any 15-day period in which the utility has the obligation to respond, but must wait until the 15-day period has passed.

The utility may respond to the complaint within ten days of service.

The Commission will limit its review to the issues identified in the complaint and response, and utilize a process similar to the arbitration process adopted to facilitate the execution of interconnection agreements among telecommunications carriers. See OAR 860, Division 016. The administrative law judge will not act as an arbitrator.

SPECIAL CONDITIONS

- 1. Delivery of energy by Seller will be at a voltage, phase, frequency, and power factor as specified by the Company.
- 2. If the Seller also receives retail Electricity Service from the Company at the same location, any payments under this schedule will be credited to the Seller's retail Electricity Service bill. At the option of the Customer, any net credit over \$10.00 will be paid by check to the Customer.
- 3. Unless required by state or federal law, if the 1978 Public Utility Regulatory Policies Act (PURPA) is repealed, PPAs entered into pursuant to this schedule will not terminate prior to the Standard or Negotiated PPA's termination date.

TERM OF AGREEMENT

Not less than one year and not to exceed 20 years.

STANDARD RENEWABLE OFF-SYSTEM VARIABLE POWER PURCHASE

AGREEMENT

THIS AGREEMENT is between <u>Blue Marmot VI LLC</u> ("Seller") and Portland General Electric Company ("PGE") (hereinafter each a "Party" or collectively, "Parties") and is effective upon execution by both Parties ("Effective Date").

RECITALS

Seller intends to construct, own, operate and maintain a <u>Solar</u> facility for the generation of electric power located in <u>Lake</u>, County, <u>Oregon @ W 120.498</u>, N 42.122 with a Nameplate Capacity Rating of <u>10000</u> kilowatt ("kW"), as further described in Exhibit A ("Facility"); and

Seller intends to operate the Facility as a "Qualifying Facility," as such term is defined in Section 3.1.3, below.

Seller shall sell and PGE shall purchase the entire Net Output, as such term is defined in Section 1.21, below, from the Facility in accordance with the terms and conditions of this Agreement.

AGREEMENT

NOW, THEREFORE, the Parties mutually agree as follows:

SECTION 1: DEFINITIONS

When used in this Agreement, the following terms shall have the following meanings:

- 1.1. "As-built Supplement" means the supplement to Exhibit A provided by Setter in accordance with Section 4.3 following completion of construction of the Facility, describing the Facility as actually built.
- 1.2. "Base Hours" is defined as the total number of hours in each Contract Year (8,760 or 8,784 for leap year)
- 1.3. "Billing Period" means from the start of the first day of each calendar month to the end of the last day of each calendar month.
- 1.4. "Cash Escrow" means an agreement by two parties to place money into the custody of a third party for delivery to a grantee only after the fulfillment of the conditions specified.
- 1.5. "Commercial Operation Date" means the date that the Facility is deemed by PGE to be fully operational and reliable. PGE may, at its discretion require, among other things, that all of the following events have occurred:
- 1.5.1. (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from a Licensed

Professional Engineer ("LPE") acceptable to PGE in its reasonable judgment stating that the Facility is able to generate electric power reliably in accordance with the terms and conditions of this Agreement (certifications required under this Section 1.5 can be provided by one or more LPEs);

- 1.5.2. Start-Up Testing of the Facility has been completed in accordance with Section 1.36;
- 1.5.3. (facilities with nameplate under 500 kW exempt from following requirement) After PGE has received notice of completion of Start-Up Testing, PGE has received a certificate addressed to PGE from an LPE stating that the Facility has operated for testing purposes under this Agreement and was continuously mechanically available for operation for a minimum of 120 hours. The Facility must provide ten (10) working days written notice to PGE prior to the start of the initial testing period. If the mechanical availability of the Facility is interrupted during this initial testing period or any subsequent testing period, the Facility shall promptly start a new Test Period and provide PGE forty-eight (48) hours written notice prior to the start of such testing period;
- 1.5.4. (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from an LPE stating that all required interconnection facilities have been constructed and all required interconnection tests have been completed;
- 1.5.5. (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from an LPE stating that Seller has obtained all Required Facility Documents and, if requested by PGE in writing, has provided copies of any or all such requested Required Facility Documents;
- 1.5.6. PGE has received a copy of the executed Generation Interconnection and Transmission Agreements.
- 1.6. "Contract Price" means the applicable price, including on-peak and offpeak prices, as specified in the Schedule.
- 1.7. "Contract Year" means each twelve (12) month period commencing upon the Commercial Operation Date or its anniversary during the Term, except the final Contract Year will be the period from the last anniversary of the Commercial Operation Date during the Term until the end of the Term.
 - 1.8. "Effective Date" has the meaning set forth in Section 2.1.
- 1.9. "Environmental Attributes" shall mean any and all claims, credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical or other substance to the air, soil or water. Environmental Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil or water such as (subject to the foregoing) sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; and (2) any avoided emissions of carbon dioxide (CO2), methane (CH4), and other greenhouse gasses (GHGs) that have been determined by the United Nations

Intergovernmental Panel on Climate Change to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere.

- 1.10. "Facility" has the meaning set forth in the Recitals.
- 1.11. "Generation Interconnection Agreement" means an agreement governing the interconnection of the Facility with PacifiCorp electric system.
- 1.12. "Generation Unit" means each separate electrical generator that contributes toward Nameplate Capacity Rating included in Exhibit A. For solar facilities, a generating unit is a complete solar electrical generation system within the Facility that is able to generate and deliver energy to the Point of Delivery independent of other Generation Units within the same Facility.
- 1.13. "Letter of Credit" means an engagement by a bank or other person made at the request of a customer that the issuer will honor drafts or other demands for payment upon compliance with the conditions specified in the letter of credit.
- 1.14. "Licensed Professional Engineer" or "LPE" means a person who is licensed to practice engineering in the state where the Facility is located, who has no economic relationship, association, or nexus with the Seller, and who is not a representative of a consulting engineer, contractor, designer or other individual involved in the development of the Facility, or of a manufacturer or supplier of any equipment installed in the Facility. Such Licensed Professional Engineer shall be licensed in an appropriate engineering discipline for the required certification being made and be acceptable to PGE in its reasonable judgment.
- 1.15. "Lost Energy" means "Lost Energy" means ((the Guarantee of Mechanical Availability as set forth in 3.1.10 / MAP) X Net Output for a Calendar Year) Net Output for the Calendar Year. Lost Energy shall be zero unless the result of the calculation in this subsection results in a positive number.
- 1.16. "Lost Energy Value" means Lost Energy X the excess of the annual time-weighted average Mid-C Index Price for On Peak Hours and Off Peak Hours over the time weighted average Contract Price for On Peak and Off Peak Hours for the corresponding time period (provided that such excess shall not exceed the Contract Price and further provided that Lost Energy is deemed to be zero prior to reaching the Commercial Operation Date) plus any reasonable costs incurred by PGE to purchase replacement power and/or transmission to deliver the replacement power to the Point of Delivery (For Start-Up Lost Energy Value See 1.35).
- 1.17. "Mechanical Availability Percentage" or "MAP" shall mean that percentage for any Contract Year for the Facility calculated in accordance with the following formula:

MAP = 100 X (Operational Hours) /(Base Hours X Number of Units)

1.18. "Mid-C Index Price" means the Day Ahead Intercontinental Exchange ("ICE") index price for the bilateral OTC market for energy at the Mid-C Physical for Average On Peak Power and Average Off Peak Power found on the following website:

https://www.theice.com/products/OTC/Physical-Energy/Electricity. In the event ICE no longer publishes this index, PGE and the Seller agree to select an alternative successor index representative of the Mid-C trading hub.

- 1.19. "Nameplate Capacity Rating" means the maximum capacity of the Facility as stated by the manufacturer, expressed in kW, which shall not exceed 10,000 kW.
- 1.20. "Net Dependable Capacity" means the maximum capacity the Facility can sustain over a specified period modified for seasonal limitations, if any, and reduced by the capacity required for station service or auxiliaries.
- 1.21. "Net Output" means all energy expressed in kWhs produced by the Facility, less station and other onsite use and less transformation and transmission losses.
- 1.22. "Number of Units" means the number of Generation Units in the Facility as specified in Exhibit A.
 - 1.23. "Off-Peak Hours" has the meaning provided in the Schedule.
 - 1.24. "On-Peak Hours" has the meaning provided in the Schedule.
- 1.25. "Operational Hours" for the Facility means the total across all Generation Units of the number of hours each of the Facility's Generation Units are potentially capable of producing power at its Nameplate Capacity Rating regardless of actual weather conditions, season and the time of day or night, without any mechanical operating constraint or restriction, and potentially capable of delivering such power to the Point of Delivery in a Contract Year. During up to, but not more than, two hundred (200) hours of Planned Maintenance during a Contract Year for each Generation Unit and hours during which an event of Force Majeure exists, a Generation Unit shall be considered potentially capable of delivering such power to the Point of Delivery. For example, in the absence of any Planned Maintenance beyond 200 hours on any Generation Unit or Event of Force Majeure, the Operational Hours for a wind farm with five (5) separate two (2) MW turbines would be 43,800 for a Contract Year.
- 1.26. "Planned Maintenance" means outages scheduled ninety (90) days in advance, with PGE's prior written consent, which shall not be unreasonably withheld.
 - 1.27. "Point of Delivery" means the PGE system.
- 1.28. "Pre-Commercial Operation Date Minimum Net Output" shall mean, unless such MWh is specifically set forth by Seller in Exhibit A, an amount in MWh equal to seventy-five percent (75%) of Nameplate Capacity Rating X thirty percent (30%) for a wind or other renewable QF or fifty percent (50%) for a solar QF X (whole months since the date selected in Section 2.2.1 / 12) X (8760 hours 200 hours (assumed Planned Maintenance)) for each month. If Seller has provided specific expected monthly Net Output amounts for the Facility in Exhibit A, "Pre-Commercial Operation Date Minimum Net Output" shall mean seventy-five percent (75%) X expected net output set forth in Exhibit A for each month.

- 1.29. "Prime Rate" means the publicly announced prime rate or reference rate for commercial loans to large businesses with the highest credit rating in the United States in effect from time to time quoted by Citibank, N.A. If a Citibank, N.A. prime rate is not available, the applicable Prime Rate shall be the announced prime rate or reference rate for commercial loans in effect from time to time quoted by a bank with \$10 billion or more in assets in New York City, N.Y., selected by the Party to whom interest based on the prime rate is being paid.
- 1.30. "Prudent Electrical Practices" means those practices, methods, standards and acts engaged in or approved by a significant portion of the electric power industry in the Western Electricity Coordinating Council that at the relevant time period, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with good business practices, reliability, economy, safety and expedition, and which practices, methods, standards and acts reflect due regard for operation and maintenance standards recommended by applicable equipment suppliers and manufacturers, operational limits, and all applicable laws and regulations. Prudent Electrical Practices are not intended to be limited to the optimum practice, method, standard or act to the exclusion of all others, but rather to those practices, methods and acts generally acceptable or approved by a significant portion of the electric power generation industry in the relevant region, during the relevant period, as described in the immediate preceding sentence.
- 1.31. "Required Facility Documents" means all licenses, permits, authorizations, and agreements necessary for construction, operation, interconnection, and maintenance of the Facility including without limitation those set forth in Exhibit B.
- 1.32. "RPS Attributes" means all attributes related to the Net Output generated by the Facility that are required in order to provide PGE with "qualifying electricity," as that term is defined in Oregon's Renewable Portfolio Standard Act, Ore. Rev. Stat. 469A.010, in effect at the time of execution of this Agreement. RPS Attributes do not include Environmental Attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity and not needed to ensure that there are zero net emissions associated with the generation of electricity.
- 1.33. "Schedule" shall mean PGE Schedule 201 filed with the Oregon Public Utilities Commission ("Commission") in effect on the Effective Date of this Agreement and attached hereto as Exhibit D, the terms of which are hereby incorporated by reference.
- 1.34. "Senior Lien" means a prior lien which has precedence as to the property under the lien over another lien or encumbrance
- 1.35. "Start-Up Lost Energy Value" means for the period after the date specified in Section 2.2.2 but prior to achievement of the Commercial Operation Date: zero, unless the Net Output is less than the pro-rated Pre-Commercial Operation Date Minimum Net Output for the applicable delay period, and the time-weighted average of the delay period's Mid-C Index Price for On-Peak Hours and Off-Peak Hours is greater

than the time-weighted average of the delay period's Contract Price for On-Peak Hours and Off-Peak Hours, in which case Startup Lost Energy Value equals: (pro-rated Pre-Commercial Operation Date Minimum Net Output for the applicable period - Net Output for the applicable period) X (the lower of: the time-weighted average of the Contract Price for On-Peak hours and Off-Peak Hours during the applicable period; or (the time-weighted average of the Mid-C Index Price for On-Peak Hours and Off-Peak Hours during the applicable period)). The time-weighted average in this section will reflect the relative proportions of On-Peak Hours and Off-Peak Hours in each day.

- 1.36. "Start-Up Testing" means the completion of applicable required factory and start-up tests as set forth in Exhibit C.
- 1.37. "Step-in Rights" means the right of one party to assume an intervening position to satisfy all terms of an agreement in the event the other party fails to perform its obligations under the agreement.
- 1.38. "Term" shall mean the period beginning on the Effective Date and ending on the Termination Date.
- 1.39. "Test Period" shall mean a period of sixty (60) days or a commercially reasonable period determined by the Seller.
- 1.40. "Transmission Agreement" means an agreement executed by the Seller and the Transmission Provider(s) for Transmission Services.
- 1.41. "Transmission Curtailment" means a limitation on Seller's ability to deliver any portion of the scheduled energy to PGE due to the unavailability of transmission to the Point of Delivery (for any reason other than Force Majeure).
- 1.42. "Transmission Curtailment Replacement Energy Cost" means the greater of zero or the amount calculated as: ((Mid-C Index Price Contract Price) X curtailed energy) for periods of Transmission Curtailment.
- 1.43. "Transmission Provider(s)" means the signatory (other than the Seller) to the Transmission Agreement.
- 1.44. "Transmission Services" means any and all services (including but not limited to ancillary services and control area services) required for the firm transmission and delivery of Energy from the Facility to the Point of Delivery for a term not less than the Term of this Agreement.

References to Recitals, Sections, and Exhibits are to be the recitals, sections and exhibits of this Agreement.

SECTION 2: TERM; COMMERCIAL OPERATION DATE

2.1. This Agreement shall become effective upon execution by both Parties ("Effective Date").

- 2.2. Time is of the essence of this Agreement, and Seller's ability to meet certain requirements prior to the Commercial Operation Date and to complete all requirements to establish the Commercial Operation Date is critically important. Therefore,
- 2.2.1. By **November 1, 2019** Seller shall begin initial deliveries of Net Output; and
- 2.2.2. By <u>November 30, 2019</u> Seller shall have completed all requirements under Section 1.5 and shall have established the Commercial Operation Date.
- 2.2.3. Unless the Parties agree in writing that a later Commercial Operation Date is reasonable and necessary, the Commercial Operation Date shall be no more than three (3) years from the Effective Date. PGE will not unreasonably withhold agreement to a Commercial Operation Date that is more than three (3) years from the Effective date if the Seller has demonstrated that a later Commercial Operation Date is reasonable and necessary.
- 2.3. This Agreement shall terminate on <u>18 years after effective date</u>, or the date the Agreement is terminated in accordance with Section 8 or 11, whichever is earlier ("Termination Date").

SECTION 3: REPRESENTATIONS AND WARRANTIES

- 3.1. Seller and PGE represent, covenant, and warrant as follows:
- 3.1.1. Seller warrants it is a <u>Limited liability company</u> duly organized under the laws of **Delaware**.
- 3.1.2. Seller warrants that the execution and delivery of this Agreement does not contravene any provision of, or constitute a default under, any indenture, mortgage, or other material agreement binding on Seller or any valid order of any court, or any regulatory agency or other body having authority to which Seller is subject.
- 3.1.3. Seller warrants that the Facility is and shall for the Term of this Agreement continue to be a "Qualifying Facility" ("QF") as that term is defined in the version of 18 C.F.R. Part 292 in effect on the Effective Date. Seller has provided the appropriate QF certification, which may include a Federal Energy Regulatory Commission ("FERC") self-certification to PGE prior to PGE's execution of this Agreement. At any time during the Term of this Agreement, PGE may require Seller to provide PGE with evidence satisfactory to PGE in its reasonable discretion that the Facility continues to qualify as a QF under all applicable requirements.
- 3.1.4. Seller warrants that it has not within the past two (2) years been the debtor in any bankruptcy proceeding, and Seller is and will continue to be for the Term of this Agreement current on all of its financial obligations.
- 3.1.5. Seller warrants that during the Term of this Agreement, all of Seller's right, title and interest in and to the Facility shall be free and clear of all liens and encumbrances other than liens and encumbrances arising from third-party financing of the Facility other than workers', mechanics', suppliers' or similar liens, or tax liens, in

each case arising in the ordinary course of business that are either not yet due and payable or that have been released by means of a performance bond acceptable to PGE posted within eight (8) calendar days of the commencement of any proceeding to foreclose the lien.

- 3.1.6. Seller warrants that it will design and operate the Facility consistent with Prudent Electrical Practices.
- 3.1.7. Seller warrants that the Facility has a Nameplate Capacity Rating not greater than 10,000 kW.
 - 3.1.8. Seller warrants that Net Dependable Capacity of the Facility is 10,000 kW.
- 3.1.9. Seller estimates that the average annual Net Output to be delivered by the Facility to PGE is <u>21,921,601</u> kilowatt-hours ("kWh"), which amount PGE will include in its resource planning.
- 3.1.10. Seller represents and warrants that the Facility shall achieve the following Mechanical Availability Percentages ("Guarantee of Mechanical Availability"):
- 3.1.10.1. Ninety percent (90%) beginning in the first Contract Year and extending through the Term for the Facility, if the Facility was operational and sold electricity to PGE or another buyer prior to the Effective Date of this Agreement; or
- 3.1.10.2. Ninety percent (90%) beginning in Contract Year three and extending throughout the remainder of the Term.
- 3.1.10.3. Annually, within 90 days of the end of each Contract Year, Seller shall send to PGE a detailed written report demonstrating and providing evidence of the actual MAP for the previous Contract Year.
- 3.1.10.4. Seller's failure to meet the Guarantee of Mechanical Availability in a Calendar Year shall result in damages payable to PGE by Seller equal to the Lost Energy Value. PGE shall bill Seller for such damages in accordance with Section 7.
- 3.1.11. Seller will deliver from the Facility to PGE at the Point of Delivery Net Output not to exceed a maximum of 33,750,000 kWh of Net Output during each Contract Year ("Maximum Net Output"). The cost of delivering energy from the Facility to PGE is the sole responsibility of the Seller.
- 3.1.12. By the Commercial Operation Date, Seller has entered into a Generation Interconnection Agreement for a term not less than the term of this Agreement.
- 3.1.13. PGE warrants that it has not within the past two (2) years been the debtor in any bankruptcy proceeding, and PGE is and will continue to be for the Term of this Agreement current on all of its financial obligations.
- 3.1.14. Seller warrants that the Facility satisfies the eligibility requirements specified in the Definition of a Small Cogeneration Facility or Small Power Production Facility Eligible to Receive the Standard Renewable Rates and Standard Renewable PPA in PGE's Schedule and Seller will not make any changes in its ownership, control or management during the term of this Agreement that would cause it to not be in

compliance with the Definition of a Small Cogeneration Facility or Small Power Production Facility Eligible to Receive the Standard Renewable Rates and Standard Renewable PPA in PGE's Schedule. Seller will provide, upon request by PGE not more frequently than every 36 months, such documentation and information as may be reasonably required to establish Seller's continued compliance with such Definition. PGE agrees to take reasonable steps to maintain the confidentiality of any portion of the above described documentation and information that the Seller identifies as confidential except PGE will provide all such confidential information to the Commission upon the Commission's request.

3.1.15. Seller warrants that it will comply with all requirements necessary for all Transferred RECs (as defined in Section 4.5) associated with Net Output to be issued, monitored, accounted for, and transferred by and through the Western Renewable Energy Generation System consistent with the provisions of OAR 330-160-0005 through OAR 330-160-0050. PGE warrants that it will reasonably cooperate in Seller's efforts to meet such requirements, including, for example serving as the qualified reporting entity for the Facility if the Facility is located in PGE's balancing authority.

SECTION 4: DELIVERY OF POWER, PRICE AND ENVIRONMENTAL ATTRIBUTES

- 4.1. Commencing on the Effective Date and continuing through the Term of this Agreement, Seller shall sell to PGE the entire Net Output delivered from the Facility at the Point of Delivery.
 - 4.2. PGE shall pay Seller the Contract Price for all delivered Net Output.
- 4.3. Upon completion of construction of the Facility, Seller shall provide PGE an As-built Supplement to specify the actual Facility as built. Seller shall not increase the Nameplate Capacity Rating above that specified in Exhibit A or increase the ability of the Facility to deliver Net Output in quantities in excess of the Net Dependable Capacity, or the Maximum Net Output as described in Section 3.1.11 above, through any means including, but not limited to, replacement, modification, or addition of existing equipment, except with prior written notice to PGE. In the event Seller increases the Nameplate Capacity Rating of the Facility to no more than 10,000 kW pursuant to this section, PGE shall pay the Contract Price for the additional delivered Net Output. In the event Seller increases the Nameplate Capacity Rating to greater than 10,000 kW, then Seller shall be required to enter into a new power purchase agreement for all delivered Net Output proportionally related to the increase of Nameplate Capacity above 10,000 kW.
- 4.4. Seller shall provide preschedules for all deliveries of energy hereunder, including identification of receiving and generating control areas, by 9:00:00 PPT on the last business day prior to the scheduled date of delivery. All energy shall be scheduled according to the most current North America Energy Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) scheduling rules and practices. The Parties' respective representatives shall maintain hourly real-time schedule coordination; provided, however, that in the absence of such coordination, the hourly schedule established by the exchange of preschedules shall be considered final. Seller

and PGE shall maintain records of hourly energy schedules for accounting and operating purposes. The final E-Tag shall be the controlling evidence of the Parties' schedule. All energy shall be prescheduled according to customary WECC scheduling practices. Seller shall make commercially reasonable efforts to schedule in any hour an amount equal to its expected Net Output for such hour. Seller shall maintain a minimum of two years records of Net Output and shall agree to allow PGE to have access to such records and to imbalance information kept by the Transmission Provider.

From the start of the Renewable Resource Deficiency Period through the remainder of the Term of this Agreement, Seller shall provide and PGE shall acquire the RPS Attributes for the Contract Years as specified in the Schedule and Seller shall retain ownership of all other Environmental Attributes (if any). During the Renewable Resource Sufficiency Period, Seller shall retain all Environmental Attributes in accordance with the Schedule. The Contract Price includes full payment for the Net Output and any RPS Attributes transferred to PGE under this Agreement. With respect to Environmental Attributes not transferred to PGE under this Agreement ("Seller-Retained Environmental Attributes") Seller may report under §1605(b) of the Energy Policy Act of 1992 or under any applicable program as belonging to Seller any of the Seller-Retained Environmental Attributes, and PGE shall not report under such program that such Seller-Retained Environmental Attributes belong to it. With respect to RPS Attributes transferred to PGE under this Agreement ("Transferred RECs"), PGE may report under §1605(b) of the Energy Policy Act of 1992 or under any applicable program as belonging to it any of the Transferred RECs, and Seller shall not report under such program that such Transferred RECs belong to it.

SECTION 5: OPERATION AND CONTROL

- 5.1. Seller shall operate and maintain the Facility in a safe manner in accordance with the Generation Interconnection Agreement, and Prudent Electrical Practices. PGE shall have no obligation to purchase Net Output from the Facility to the extent the interconnection of the Facility to PGE's electric system is disconnected, suspended or interrupted, in whole or in part, pursuant to the Generation Interconnection Agreement, or to the extent generation curtailment is required as a result of Seller's noncompliance with the Generation Interconnection Agreement. Seller is solely responsible for the operation and maintenance of the Facility. PGE shall not, by reason of its decision to inspect or not to inspect the Facility, or by any action or inaction taken with respect to any such inspection, assume or be held responsible for any liability or occurrence arising from the operation and maintenance by Seller of the Facility.
- 5.2. Seller agrees to provide sixty (60) days advance written notice of any scheduled maintenance that would require shut down of the Facility for any period of time.
- 5.3. If the Facility ceases operation for unscheduled maintenance, Seller immediately shall notify PGE of the necessity of such unscheduled maintenance, the time when such maintenance has occurred or will occur, and the anticipated duration of such maintenance. Seller shall take all reasonable measures and exercise its best

efforts to avoid unscheduled maintenance, to limit the duration of such unscheduled maintenance, and to perform unscheduled maintenance during Off-Peak hours.

SECTION 6: CREDITWORTHINESS

In the event Seller: a) is unable to represent or warrant as required by Section 3 that it has not been a debtor in any bankruptcy proceeding within the past two (2) years; b) becomes such a debtor during the Term; or c) is not or will not be current on all its financial obligations, Seller shall immediately notify PGE and shall promptly (and in no less than 10 days after notifying PGE) provide default security in an amount reasonably acceptable to PGE in one of the following forms: Senior Lien, Step-in Rights, a Cash Escrow or Letter of Credit. The amount of such default security that shall be acceptable to PGE shall be equal to: (annual On Peak Hours) X (On Peak Price – Off Peak Price) X (Net Dependable Capacity). Notwithstanding the foregoing, in the event Seller is not current on construction related financial obligations, Seller shall notify PGE of such delinquency and PGE may, in its discretion, grant an exception to the requirements to provide default security if the QF has negotiated financial arrangements with the construction loan lender that mitigate Seller's financial risk to PGE.

SECTION 7: BILLINGS, COMPUTATIONS AND PAYMENTS

- 7.1. On or before the thirtieth (30th) day following the end of each Billing Period, PGE shall send to Seller payment for Seller's deliveries of Net Output to PGE, together with computations supporting such payment. PGE may offset any such payment to reflect amounts owing from Seller to PGE pursuant to this Agreement and any other agreement related to the Facility between the Parties or otherwise. On or before the thirtieth (30th) day following the end of each Contract Year, PGE shall bill for any Lost Energy Value accrued pursuant to this Agreement.
- 7.2. Any amounts owing after the due date thereof shall bear interest at the Prime Rate plus two percent (2%) from the date due until paid; provided, however, that the interest rate shall at no time exceed the maximum rate allowed by applicable law.

SECTION 8: DEFAULT, REMEDIES AND TERMINATION

- 8.1. In addition to any other event that may constitute a default under this Agreement, the following events shall constitute defaults under this Agreement:
- 8.1.1. Breach by Seller or PGE of a representation or warranty, except for Section 3.1.4, set forth in this Agreement.
- 8.1.2. Seller's failure to provide default security, if required by Section 6, prior to delivery of any Net Output to PGE or within 10 days of notice.
- 8.1.3. Seller's failure to meet the Guarantee of Mechanical Availability established in Section 3.1.10 for two consecutive Contract Years or Seller's failure to provide any written report required by that section.
 - 8.1.4. If Seller is no longer a Qualifying Facility.
 - 8.1.5. Failure of PGE to make any required payment pursuant to Section 7.1.

- 8.1.6. Seller's failure to meet the Commercial Operation Date.
- 8.2. In the event of a default under Section 8.1.6, PGE may provide Seller with written notice of default. Seller shall have one year in which to cure the default during which time the Seller shall pay PGE damages equal to the Lost Energy Value. If Seller is unable to cure the default, PGE may immediately terminate this Agreement as provided in Section 8.3. PGE's resource sufficiency/deficiency position shall have no bearing on PGE's right to terminate the Agreement under this Section 8.2.
- 8.3. In the event of a default hereunder, except as otherwise provided in this Agreement, the non-defaulting party may immediately terminate this Agreement at its sole discretion by delivering written notice to the other Party. In addition, the non-defaulting Party may pursue any and all legal or equitable remedies provided by law or pursuant to this Agreement including damages related to the need to procure replacement power. A termination hereunder shall be effective upon the date of delivery of notice, as provided in Section 20. The rights provided in this Section 8 are cumulative such that the exercise of one or more rights shall not constitute a waiver of any other rights.
- 8.4. If this Agreement is terminated as provided in this Section 8, PGE shall make all payments, within thirty (30) days, that, pursuant to the terms of this Agreement, are owed to Seller as of the time of receipt of notice of default. PGE shall not be required to pay Seller for any Net Output delivered by Seller after such notice of default.
- 8.5. In the event PGE terminates this Agreement pursuant to this Section 8, and Seller wishes to again sell Net Output to PGE following such termination, PGE in its sole discretion may require that Seller shall do so subject to the terms of this Agreement, including but not limited to the Contract Price until the Term of this Agreement (as set forth in Section 2.3) would have run in due course had the Agreement remained in effect. At such time Seller and PGE agree to execute a written document ratifying the terms of this Agreement.
- 8.6. Sections 8.1, 8.4, 8.5, 10, and 19.2 shall survive termination of this Agreement.

SECTION 9: TRANSMISSION CURTAILMENTS

- 9.1. Seller shall give PGE notice as soon as reasonably practicable of any Transmission Curtailment that is likely to affect Seller's ability to deliver any portion of energy scheduled pursuant to Section 4.4 of this Agreement.
- 9.2. If as the result of a Transmission Curtailment, Seller does not deliver any portion of energy (including real-time adjustments), scheduled pursuant to Section 4.4 of this Agreement, Seller shall pay PGE the Transmission Curtailment Replacement Energy Cost for the number of MWh of energy reasonably determined by PGE as the difference between (i) the scheduled energy that would have been delivered to PGE under this Agreement during the period of Transmission Curtailment and (ii) the actual energy, if any, that was delivered to PGE for the period.

SECTION 10: INDEMNIFICATION AND LIABILITY

- 10.1. Seller agrees to defend, indemnify and hold harmless PGE, its directors, officers, agents, and representatives against and from any and all loss, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with Seller's delivery of electric power to PGE or with the facilities at or prior to the Point of Delivery, or otherwise arising out of this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PGE, Seller or others, excepting to the extent such loss, claim, action or suit may be caused by the negligence of PGE, its directors, officers, employees, agents or representatives.
- 10.2. PGE agrees to defend, indemnify and hold harmless Seller, its directors, officers, agents, and representatives against and from any and all loss, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with PGE's receipt of electric power from Seller or with the facilities at or after the Point of Delivery, or otherwise arising out of this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PGE, Seller or others, excepting to the extent such loss, claim, action or suit may be caused by the negligence of Seller, its directors, officers, employees, agents or representatives.
- 10.3. Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a Party to this Agreement. No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or to the public, nor affect the status of PGE as an independent public utility corporation or Seller as an independent individual or entity.
- 10.4. NEITHER PARTY SHALL BE LIABLE TO THE OTHER FOR SPECIAL, PUNITIVE, INDIRECT OR CONSEQUENTIAL DAMAGES, WHETHER ARISING FROM CONTRACT, TORT (INCLUDING NEGLIGENCE), STRICT LIABILITY OR OTHERWISE.

SECTION 11: INSURANCE

11.1. Prior to the connection of the Facility to PGE's electric system, provided such Facility has a design capacity of 200 kW or more, Seller shall secure and continuously carry for the Term hereof, with an insurance company or companies rated not lower than "B+" by the A. M. Best Company, insurance policies for bodily injury and property damage liability. Such insurance shall include provisions or endorsements naming PGE, it directors, officers and employees as additional insureds; provisions that such insurance is primary insurance with respect to the interest of PGE and that any insurance or self-insurance maintained by PGE is excess and not contributory insurance with the insurance required hereunder; a cross-liability or severability of

insurance interest clause; and provisions that such policies shall not be canceled or their limits of liability reduced without thirty (30) days' prior written notice to PGE. Initial limits of liability for all requirements under this section shall be \$1,000,000 million single limit, which limits may be required to be increased or decreased by PGE as PGE determines in its reasonable judgment economic conditions or claims experience may warrant.

- 11.2. Prior to the connection of the Facility to PGE's electric system, provided such facility has a design capacity of 200 kW or more, Seller shall secure and continuously carry for the Term hereof, in an insurance company or companies rated not lower than "B+" by the A. M. Best Company, insurance acceptable to PGE against property damage or destruction in an amount not less than the cost of replacement of the Facility. Seller promptly shall notify PGE of any loss or damage to the Facility. Unless the Parties agree otherwise, Seller shall repair or replace the damaged or destroyed Facility, or if the facility is destroyed or substantially destroyed, it may terminate this Agreement. Such termination shall be effective upon receipt by PGE of written notice from Seller. Seller shall waive its insurers' rights of subrogation against PGE regarding Facility property losses.
- 11.3. Prior to the connection of the Facility to PGE's electric system and at all other times such insurance policies are renewed or changed, Seller shall provide PGE with a copy of each insurance policy required under this Section, certified as a true copy by an authorized representative of the issuing insurance company or, at the discretion of PGE, in lieu thereof, a certificate in a form satisfactory to PGE certifying the issuance of such insurance. If Seller fails to provide PGE with copies of such currently effective insurance policies or certificates of insurance, PGE at its sole discretion and without limitation of other remedies, may upon ten (10) days advance written notice by certified or registered mail to Seller either withhold payments due Seller until PGE has received such documents, or purchase the satisfactory insurance and offset the cost of obtaining such insurance from subsequent power purchase payments under this Agreement.

SECTION 12: FORCE MAJEURE

12.1. As used in this Agreement, "Force Majeure" or "an event of Force Majeure" means any cause beyond the reasonable control of the Seller or of PGE which, despite the exercise of due diligence, such Party is unable to prevent or overcome. By way of example, Force Majeure may include but is not limited to acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes, and other labor disturbances, earthquakes, fires, lightning, epidemics, sabotage, restraint by court order or other delay or failure in the performance as a result of any action or inaction on behalf of a public authority which by the exercise of reasonable foresight such Party could not reasonably have been expected to avoid and by the exercise of due diligence, it shall be unable to overcome, subject, in each case, to the requirements of the first sentence of this paragraph. Force Majeure, however, specifically excludes the cost or availability of resources to operate the Facility, changes in market conditions that affect

the price of energy or transmission, wind or water droughts, and obligations for the payment of money when due.

- 12.2. If either Party is rendered wholly or in part unable to perform its obligation under this Agreement because of an event of Force Majeure, that Party shall be excused from whatever performance is affected by the event of Force Majeure to the extent and for the duration of the Force Majeure, after which such Party shall recommence performance of such obligation, provided that:
- 12.2.1. the non-performing Party, shall, promptly, but in any case within one (1) week after the occurrence of the Force Majeure, give the other Party written notice describing the particulars of the occurrence; and
- 12.2.2. the suspension of performance shall be of no greater scope and of no longer duration than is required by the Force Majeure; and
- 12.2.3. the non-performing Party uses its best efforts to remedy its inability to perform its obligations under this Agreement.
- 12.3. No obligations of either Party which arose before the Force Majeure causing the suspension of performance shall be excused as a result of the Force Majeure.
- 12.4. Neither Party shall be required to settle any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to the Party's best interests.

SECTION 13: SEVERAL OBLIGATIONS

Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership or joint venture or to impose a trust or partnership duty, obligation or liability between the Parties. If Seller includes two or more parties, each such party shall be jointly and severally liable for Seller's obligations under this Agreement.

SECTION 14: CHOICE OF LAW

This Agreement shall be interpreted and enforced in accordance with the laws of the state of Oregon, excluding any choice of law rules which may direct the application of the laws of another jurisdiction.

SECTION 15: PARTIAL INVALIDITY AND PURPA REPEAL

It is not the intention of the Parties to violate any laws governing the subject matter of this Agreement. If any of the terms of the Agreement are finally held or determined to be invalid, illegal or void as being contrary to any applicable law or public policy, all other terms of the Agreement shall remain in effect. If any terms are finally held or determined to be invalid, illegal or void, the Parties shall enter into negotiations concerning the terms affected by such decision for the purpose of achieving conformity with requirements of any applicable law and the intent of the Parties to this Agreement.

In the event the Public Utility Regulatory Policies Act (PURPA) is repealed, this Agreement shall not terminate prior to the Termination Date, unless such termination is mandated by state or federal law.

SECTION 16: WAIVER

Any waiver at any time by either Party of its rights with respect to a default under this Agreement or with respect to any other matters arising in connection with this Agreement must be in writing, and such waiver shall not be deemed a waiver with respect to any subsequent default or other matter.

SECTION 17: GOVERNMENTAL JURISDICTION AND AUTHORIZATIONS

This Agreement is subject to the jurisdiction of those governmental agencies having control over either Party or this Agreement. Seller shall at all times maintain in effect all local, state and federal licenses, permits and other approvals as then may be required by law for the construction, operation and maintenance of the Facility, and shall provide upon request copies of the same to PGE.

SECTION 18: SUCCESSORS AND ASSIGNS

This Agreement and all of the terms hereof shall be binding upon and inure to the benefit of the respective successors and assigns of the Parties. No assignment hereof by either Party shall become effective without the written consent of the other Party being first obtained and such consent shall not be unreasonably withheld. Notwithstanding the foregoing, either Party may assign this Agreement without the other Party's consent as part of (a) a sale of all or substantially all of the assigning Party's assets, or (b) a merger, consolidation or other reorganization of the assigning Party.

SECTION 19: ENTIRE AGREEMENT

- 19.1. This Agreement supersedes all prior agreements, proposals, representations, negotiations, discussions or letters, whether oral or in writing, regarding PGE's purchase of Net Output from the Facility. No modification of this Agreement shall be effective unless it is in writing and signed by both Parties.
- 19.2. By executing this Agreement, Seller releases PGE from any third party claims related to the Facility, known or unknown, which may have arisen prior to the Effective Date.

SECTION 20: NOTICES

20.1. All notices except as otherwise provided in this Agreement shall be in writing, shall be directed as follows and shall be considered delivered if delivered in person or when deposited in the U.S. Mail, postage prepaid by certified or registered mail and return receipt requested:

To Seller:

Blue Marmot VI LLC c/o EDP Renewables North America LLC; Attention: General Counsel 808 Travis, Suite 700 Houston, Texas 77002

with a copy to:

To PGE:

Contracts Manager

QF Contracts, 3WTC0306 PGE - 121 SW Salmon St. Portland, Oregon 97204

20.2 The Parties may change the person to whom such notices are addressed, or their addresses, by providing written notices thereof in accordance with this Section 20.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed in their respective names as of the Effective Date.

Approved By:
Business
Terms
Credit
Legal
Flisk Mgt.

19

Brian Hayes Executive Vice President, Asset Operations

3/29/17

EXHIBIT A DESCRIPTION OF SELLER'S FACILITY

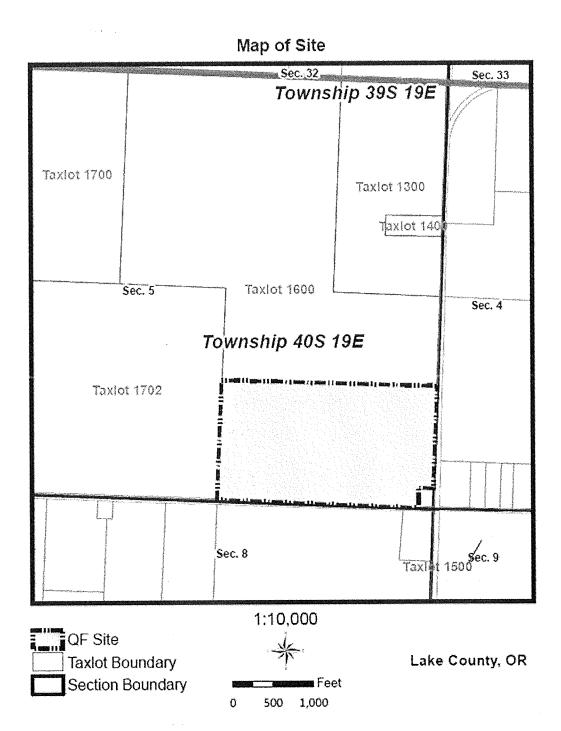
The facility will be a solar PV plant consisting of 39,324 polycrystalline modules of nominal 335W rating each. Total plant rating will be 13.174MWdc/10MWac. Modules will be mounted to single-axis trackers.

Central inverter stations will be located at intermediate points in the PV field. Modules will be evenly distributed to the inverter stations. The total inverter nameplate rating will be 10.0MWac. Each inverter will be directly coupled to a 34.5kV step-up transformer. The transformers will be connected to a 34.5kV AC collection system, which will feed into the plant switchgear.

The plant switchgear will feed a 34.5kV transmission line, which will run overhead approximately 11.1 miles to the PacifiCorp Mile-Hi Substation. Inside the Mile-Hi Substation, the transmission line will connect to a new bay containing a facility-owned 34.5kV/115kV GSU transformer, associated breakers, switching, bus, and controls.

The facility-owned components at Mile-Hi substation are considered part of the selfcertified qualifying facility.

Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016



19

	OH	*#i	2H	.3H	-4H	5	н	6H	-7H	ŧ	н :	3H :	ÙΗ	124	12H	: 13	H .14	អ ៈ	154	16H	171	1 :18		201	1 :2	nH:	22H	23H	: 14	жaf
arway.		0	o ·	9	0	O	0		0		66	132	125	124	4	114	118	127	100	0	13	0	0	0:	0	() (0:	0	92
ebrusig		0	0	0	0	0	0		0	14	100	143	142	14	3	140	150	126	150	3	67	0	0	Ū.	0	() !	0:	0	120
arch		0	Ü	Đ.	0		0		6.	33	173	195	132	19	7	184:	186	178	153	3	137	36	0	0	0	(3 (0	Ü	173
zđ		0	O	9	Ü	0	0		86	195	202	211	225	22	7 2	235	220	207	154		173	85	0	0	0.) !	0	0	225
áy		0	υ	0	0	0	53		132	231	243	258	254	25	3 2	246	236	244	230	3	220	167	45	0	0		9 1	0	0	287
ine		0	0.	0	D	0	35		241	253	264	268	263	25	4 2	254	251	248	24		226	203	78	Ð	0		3 1	0	0	315
έγ		0	0	0	0	0	63		203	243	251	260	25/5	26	2 :	261	254	255	248	в:	236	134	74.	0	0		3	0:	U	307
agus!		Ü	0	9	0	0	4		130	257	266	277	274	25	5 2	257	251	249	23	9	232	156	23,	Ü	0	(] 1	0	0	287
prember		0	0	0	0.	Ü	0	ι,	73	212	237	244	244	223		225	220	230	224	4	175	46	0	0	0		3. 1	0	0	235
etcher		0	0	o i	. 0	0	. 0	i i	2	109	187	187	192	18	4	197	212	226	136	3.	72	0	0	0	0		0. (0	0	175
wenbe:		0	Ü	0	Q.	0	5		0	25	95	119.	117	11	6	115	135	131	7	7	1	0	0	0	0	(0 1	0	Ø:	93
cember		0	0	0.	O:	0	0		0	0	54	103	102	100	5	103	111	122	E4		0	0.	0	0	0		3 1	0	0	75
164		-2	-2	-2	~2	-2	215		523	1637	2145	2396	2417	2345	5 23	332	2347	2375	2125	5 1	552	888	226	-2	-2	-3	2. ~	2	-2	2350

FEDERAL ENERGY REGULATORY COMMISSION WASHINGTON, DC

OMB Control # 1902-0075 Expiration 06/30/2019

Form 556 Certification of Qualifying Facility (QF) Status for a Small Power Production or Cogeneration Facility

General

Questions about completing this form should be sent to <u>Form556@ferc.gov</u>. Information about the Commission's QF program, answers to frequently asked questions about QF requirements or completing this form, and contact information for QF program staff are available at the Commission's QF website, www.ferc.gov/QF. The Commission's QF website also provides links to the Commission's QF regulations (18 C.F.R. § 131.80 and Part 292), as well as other statutes and orders pertaining to the Commission's QF program.

Who Must File

Any applicant seeking QF status or recertification of QF status for a generating facility with a net power production capacity (as determined in lines 7a through 7g below) greater than 1000 kW must file a self-certification or an application for Commission certification of QF status, which includes a properly completed Form 556. Any applicant seeking QF status for a generating facility with a net power production capacity 1000 kW or less is exempt from the certification requirement, and is therefore not required to complete or file a Form 556. See 18 C.F.R. § 292.203.

How to Complete the Form 556

This form is intended to be completed by responding to the items in the order they are presented, according to the instructions given. If you need to back-track, you may need to clear certain responses before you will be allowed to change other responses made previously in the form. If you experience problems, click on the nearest help button () for assistance, or contact Commission staff at Form556@ferc.gov.

Certain lines in this form will be automatically calculated based on responses to previous lines, with the relevant formulas shown. You must respond to all of the previous lines within a section before the results of an automatically calculated field will be displayed. If you disagree with the results of any automatic calculation on this form, contact Commission staff at Form556@ferc.gov to discuss the discrepancy before filing.

You must complete all lines in this form unless instructed otherwise. Do not alter this form or save this form in a different format. Incomplete or altered forms, or forms saved in formats other than PDF, will be rejected.

How to File a Completed Form 556

Applicants are required to file their Form 556 electronically through the Commission's eFiling website (see instructions on page 2). By filing electronically, you will reduce your filing burden, save paper resources, save postage or courier charges, help keep Commission expenses to a minimum, and receive a much faster confirmation (via an email containing the docket number assigned to your facility) that the Commission has received your filing.

If you are simultaneously filing both a waiver request and a Form 556 as part of an application for Commission certification, see the "Waiver Requests" section on page 3 for more information on how to file.

Paperwork Reduction Act Notice

This form is approved by the Office of Management and Budget. Compliance with the information requirements established by the FERC Form No. 556 is required to obtain or maintain status as a QF. See 18 C.F.R. § 131.80 and Part 292. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The estimated burden for completing the FERC Form No. 556, including gathering and reporting information, is as follows: 3 hours for self-certification of a small power production facility, 8 hours for self-certifications of a cogeneration facility, 6 hours for an application for Commission certification of a small power production facility, and 50 hours for an application for Commission certification of a cogeneration facility. Send comments regarding this burden estimate or any aspect of this collection of information, including suggestions for reducing this burden, to the following: Information Clearance Officer, Office of the Executive Director (ED-32), Federal Energy Regulatory Commission, 888 First Street N.E., Washington, DC 20426 (<u>DataClearance@ferc.gov</u>); and Desk Officer for FERC, Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (oira_submission@omb.eop.gov). Include the Control No. 1902-0075 in any correspondence.

Electronic Filing (eFiling)

To electronically file your Form 556, visit the Commission's QF website at www.ferc.gov/QF and click the eFiling link.

If you are eFiling your first document, you will need to register with your name, email address, mailing address, and phone number. If you are registering on behalf of an employer, then you will also need to provide the employer name, alternate contact name, alternate contact phone number and and alternate contact email.

Once you are registered, log in to eFiling with your registered email address and the password that you created at registration. Follow the instructions. When prompted, select one of the following QF-related filing types, as appropriate, from the Electric or General filing category.

Filing category	Filing Type as listed in eFiling	Description		
	(Fee) Application for Commission Cert. as Cogeneration QF	Use to submit an application for Commission certification or Commission recertification of a cogeneration facility as a QF.		
	(Fee) Application for Commission Cert. as Small Power QF	Use to submit an application for Commission certification or Commission recertification of a small power production facility as a QF.		
	Self-Certification Notice (QF, EG, FC)	Use to submit a notice of self- certification of your facility (cogeneration or small power production) as a QF.		
Electric	Self-Recertification of Qualifying Facility (QF)	Use to submit a notice of self- recertification of your facility (cogeneration or small power production) as a QF.		
	Supplemental Information or Request	Use to correct or supplement a Form 556 that was submitted with errors or omissions, or for which Commission staff has requested additional information. Do not use this filing type to report new changes to a facility or its ownership; rather, use a self-recertification or Commission recertification to report such changes.		
General	(Fee) Petition for Declaratory Order (not under FPA Part 1)	Use to submit a petition for declaratory order granting a waiver of Commission QF regulations pursuant to 18 C.F.R. §§ 292.204(a) (3) and/or 292.205(c). A Form 556 is not required for a petition for declaratory order unless Commission recertification is being requested as part of the petition.		

You will be prompted to submit your filing fee, if applicable, during the electronic submission process. Filing fees can be paid via electronic bank account debit or credit card.

During the eFiling process, you will be prompted to select your file(s) for upload from your computer.

Filing Fee

No filing fee is required if you are submitting a self-certification or self-recertification of your facility as a QF pursuant to 18 C.F.R. § 292.207(a).

A filing fee is required if you are filing either of the following:

- (1) an application for Commission certification or recertification of your facility as a QF pursuant to 18 C.F.R. § 292.207(b), or
- (2) a petition for declaratory order granting waiver pursuant to 18 C.F.R. §§ 292.204(a)(3) and/or 292.205(c).

The current fees for applications for Commission certifications and petitions for declaratory order can be found by visiting the Commission's QF website at www.ferc.gov/QF and clicking the Fee Schedule link.

You will be prompted to submit your filing fee, if applicable, during the electronic filing process described on page 2.

Required Notice to Utilities and State Regulatory Authorities

Pursuant to 18 C.F.R. § 292.207(a)(ii), you must provide a copy of your self-certification or request for Commission certification to the utilities with which the facility will interconnect and/or transact, as well as to the State regulatory authorities of the states in which your facility and those utilities reside. Links to information about the regulatory authorities in various states can be found by visiting the Commission's QF website at www.ferc.gov/QF and clicking the Notice Requirements link.

What to Expect From the Commission After You File

An applicant filing a Form 556 electronically will receive an email message acknowledging receipt of the filing and showing the docket number assigned to the filing. Such email is typically sent within one business day, but may be delayed pending confirmation by the Secretary of the Commission of the contents of the filing.

An applicant submitting a self-certification of QF status should expect to receive no documents from the Commission, other than the electronic acknowledgement of receipt described above. Consistent with its name, a self-certification is a certification by the applicant itself that the facility meets the relevant requirements for QF status, and does not involve a determination by the Commission as to the status of the facility. An acknowledgement of receipt of a self-certification, in particular, does not represent a determination by the Commission with regard to the QF status of the facility. An applicant self-certifying may, however, receive a rejection, revocation or deficiency letter if its application is found, during periodic compliance reviews, not to comply with the relevant requirements.

An applicant submitting a request for Commission certification will receive an order either granting or denying certification of QF status, or a letter requesting additional information or rejecting the application. Pursuant to 18 C.F.R. § 292.207(b)(3), the Commission must act on an application for Commission certification within 90 days of the later of the filing date of the application or the filing date of a supplement, amendment or other change to the application.

Waiver Requests

18 C.F.R. § 292.204(a)(3) allows an applicant to request a waiver to modify the method of calculation pursuant to 18 C.F.R. § 292.204(a)(2) to determine if two facilities are considered to be located at the same site, for good cause. 18 C.F.R. § 292.205(c) allows an applicant to request waiver of the requirements of 18 C.F.R. §§ 292.205(a) and (b) for operating and efficiency upon a showing that the facility will produce significant energy savings. A request for waiver of these requirements must be submitted as a petition for declaratory order, with the appropriate filing fee for a petition for declaratory order. Applicants requesting Commission recertification as part of a request for waiver of one of these requirements should electronically submit their completed Form 556 along with their petition for declaratory order, rather than filing their Form 556 as a separate request for Commission recertification. Only the filing fee for the petition for declaratory order must be paid to cover both the waiver request and the request for recertification if such requests are made simultaneously.

18 C.F.R. § 292.203(d)(2) allows an applicant to request a waiver of the Form 556 filing requirements, for good cause. Applicants filing a petition for declaratory order requesting a waiver under 18 C.F.R. § 292.203(d)(2) do not need to complete or submit a Form 556 with their petition.

Geographic Coordinates

If a street address does not exist for your facility, then line 3c of the Form 556 requires you to report your facility's geographic coordinates (latitude and longitude). Geographic coordinates may be obtained from several different sources. You can find links to online services that show latitude and longitude coordinates on online maps by visiting the Commission's QF webpage at www.ferc.gov/QF and clicking the Geographic Coordinates link. You may also be able to obtain your geographic coordinates from a GPS device, Google Earth (available free at http://earth.google.com), a property survey, various engineering or construction drawings, a property deed, or a municipal or county map showing property lines.

Filing Privileged Data or Critical Energy Infrastructure Information in a Form 556

The Commission's regulations provide procedures for applicants to either (1) request that any information submitted with a Form 556 be given privileged treatment because the information is exempt from the mandatory public disclosure requirements of the Freedom of Information Act, 5 U.S.C. § 552, and should be withheld from public disclosure; or (2) identify any documents containing critical energy infrastructure information (CEII) as defined in 18 C.F.R. § 388.113 that should not be made public.

If you are seeking privileged treatment or CEII status for any data in your Form 556, then you must follow the procedures in 18 C.F.R. § 388.112. See www.ferc.gov/help/filing-guide/file-ceii.asp for more information.

Among other things (see 18 C.F.R. § 388.112 for other requirements), applicants seeking privileged treatment or CEII status for data submitted in a Form 556 must prepare and file both (1) a complete version of the Form 556 (containing the privileged and/or CEII data), and (2) a public version of the Form 556 (with the privileged and/or CEII data redacted). Applicants preparing and filing these different versions of their Form 556 must indicate below the security designation of this version of their document. If you are *not* seeking privileged treatment or CEII status for any of your Form 556 data, then you should not respond to any of the items on this page.

Non-Public: Applicant is seeking privileged treatment and/or CEII status for data contained in the Form 556 lines indicated below. This non-public version of the applicant's Form 556 contains all data, including the data that is redacted in the (separate) public version of the applicant's Form 556.
Public (redacted): Applicant is seeking privileged treatment and/or CEII status for data contained in the Form 556 lines indicated below. This public version of the applicants's Form 556 contains all data except for data from the lines indicated below, which has been redacted.
Privileged : Indicate below which lines of your form contain data for which you are seeking privileged treatment
Critical Energy Infrastructure Information (CEII): Indicate below which lines of your form contain data for which you are seeking CEII status

The eFiling process described on page 2 will allow you to identify which versions of the electronic documents you submit are public, privileged and/or CEII. The filenames for such documents should begin with "Public", "Priv", or "CEII", as applicable, to clearly indicate the security designation of the file. Both versions of the Form 556 should be unaltered PDF copies of the Form 556, as available for download from www.ferc.gov/QF. To redact data from the public copy of the submittal, simply omit the relevant data from the Form. For numerical fields, leave the redacted fields blank. For text fields, complete as much of the field as possible, and replace the redacted portions of the field with the word "REDACTED" in brackets. Be sure to identify above all fields which contain data for which you are seeking non-public status.

The Commission is not responsible for detecting or correcting filer errors, including those errors related to security designation. If your documents contain sensitive information, make sure they are filed using the proper security designation.

FEDERAL ENERGY REGULATORY COMMISSION WASHINGTON, DC

OMB Control # 1902-0075 Expiration 06/30/2019

Form 556 Certification of Qualifying Facility (QF) Status for a Small Power Production or Cogeneration Facility

1b Applicant street add 808 Travis Stre										
1c City		1d State/province								
Houston		TX								
1e Postal code 77002	1f Country (if not United States)		1g Telephone number 713–265–0350							
1h Has the instant facil	ity ever previously been certified as a Q	F? Yes ∑ N	No [
1i If yes, provide the do	ocket number of the last known QF filin	g pertaining to th	nis facility: QF16 - 1091 - 000							
1j Under which certification process is the applicant making this filing?										
Notice of self-certification See note below) Application for Commission certification (requires filing fee; see "Filing Fee" section on page 3)										
Note: a notice of self-certification is a notice by the applicant itself that its facility complies with the requirements for QF status. A notice of self-certification does not establish a proceeding, and the Commission does not review a notice of self-certification to verify compliance. See the "What to Expect From the Commission After You File" section on page 3 for more information.										
1k What type(s) of QF status is the applicant seeking for its facility? (check all that apply)										
Qualifying small power production facility status Qualifying cogeneration facility status										
11 What is the purpose and expected effective date(s) of this filing?										
Original certification; facility expected to be installed by and to begin operation on										
\bigcirc Change(s) to a previously certified facility to be effective on $9/6/16$ (identify type(s) of change(s) below, and describe change(s) in the Miscellaneous section starting on page 19)										
☑ Name change and/or other administrative change(s)										
☐ Change in ow	•									
Change(s) affecting plant equipment, fuel use, power production capacity and/or cogeneration thermal outp										
Supplement or correction to a previous filing submitted on										
(describe the supplement or correction in the Miscellaneous section starting on page 19)										
to the extent possil	ole, explaining any special circumstanc	es in the Miscella	cribe your situation and complete the forn neous section starting on page 19.							
previously gran orders in the M	ted by the Commission in an order dat iscellaneous section starting on page 1	ed 9)	y virtue of a waiver of certain regulations (specify any other relevant waiver							
The instant faci	lity would comply with the Commission ith this application is granted	n's QF requireme	nts if a petition for waiver submitted							
amployment of	lity complies with the Commission's re- funique or innovative technologies not tion of compliance via this form difficul	t contemplated b	s special circumstances, such as the by the structure of this form, that make describe in Misc. section starting on p. 19)							

	2a Name of contact person Leslie A. Freiman	er										
		he contact person's relation	nship to the ap	L olicant? (check one)								
	2c Which of the following describes the contact person's relationship to the applicant? (check one) Applicant (self) Employee, owner or partner of applicant authorized to represent the applicant											
ב	Employee of a company affiliated with the applicant authorized to represent the applicant on this matter											
tic	Lawyer, consultant, or other representative authorized to represent the applicant on this matter											
πa												
ori	2d Company or organization name (if applicant is an individual, check here and skip to line 2e)											
Inf	EDP Renewables North America LLC											
Contact Information	2e Street address (if same as Applicant, check here and skip to line 3a) ⊠											
nta												
0					1							
•	2f City		2g State/prov									
					'. 							
	2h Postal code	2i Country (if not United	States)									
					! 							
	3a Facility name											
on	Blue Marmot VI											
ati	3b Street address (if a street address does not exist for the facility, check here and skip to line 3c) ✓											
0.												
d L												
Identification and Location	3c Geographic coordinates: If you in then you must specify the latitude the following formula to convert degrees + (minutes/60) + (secon provided a street address for you Longitude	de and longitude coordinate to decimal degrees from of ds/3600). See the "Geogr	es of the facility degrees, minute aphic Coordinat	vin degrees (to three de s and seconds: decima tes" section on page 4 f ographic coordinates b	ecimal places). Use degrees = or help. If you							
	3d City (if unincorporated, check he	re and enter nearest city) [3e State/p	province								
 	Lakeview		Oregon									
Facility	3f County (or check here for indepe	ndent city) 🗌 3g	Country (if no	t United States)								
	Lake Identify the electric utilities that are contemplated to transact with the facility.											
			vicir che raciney.									
lities	4a Identify utility interconnecting with the facility PacifiCorp (Pacific Power)											
Uti	4b Identify utilities providing wheeling service or check here if none											
g	PacifiCorp (Pacific Powe	er)										
Transacting Utilities	4c Identify utilities purchasing the upper Portland General Electric		it or check here	if none 🗍								
Tran	4d Identify utilities providing suppl service or check here if none		oower, maintena	ance power, and/or inte	erruptible power							
	PacifiCorp (Pacific Pow	er)										

defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or a not 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451) utilities or holding companies, provide the percentage of equity interest in direct owners hold at least 10 percent equity interest in the facility, then pr	the facility held by that	ned in section which are ele- owner. If no	n ctric
two direct owners with the largest equity interest in the facility.	Electric util holdin compar	g %eo	es, quity rest
Full legal names of direct owners			100%
1) Blue Marmot VI LLC		ю П ——	%
2)		.o □ lo □	 왕
3)	V 🔲 N	.∘ □ lo □	 ક
4)		- □ No □	 %
5)		- □ <u></u>	 왕
6)		~ No ∏	
7)	V I I N	 No □	응
9)		No 🗌	% %
10)	Yes I	No 🗌	9
equity interest in the facility holding company Act of 2003 (12 distance) equity interest in the facility held by such owners. (Note that, because up another, total percent equity interest reported may exceed 100 percent.) Check here if no such upstream owners exist.			
Check here it no such abstream owners exist [% F	
	stream owners		equity erest
Full legal names of electric utility or holding company ups	stream owners		quity erest
Full legal names of electric utility or holding company ups 1) EDP Renewables North America LLC	stream owners		quity erest
Full legal names of electric utility or holding company ups 1) EDP Renewables North America LLC 2)	stream owners		quity erest
Full legal names of electric utility or holding company ups 1) EDP Renewables North America LLC 2)			quity erest
Full legal names of electric utility or holding company ups 1) EDP Renewables North America LLC 2) 3)			quity erest
Full legal names of electric utility or holding company ups 1) EDP Renewables North America LLC 2) 3) 4)			quity erest
Full legal names of electric utility or holding company ups 1) EDP Renewables North America LLC 2) 3) 4) 5)			quity erest
Full legal names of electric utility or holding company ups 1) EDP Renewables North America LLC 2)			equity erest
Full legal names of electric utility or holding company ups 1) EDP Renewables North America LLC 2) 3) 4) 5) 6) 7)			equity erest
Full legal names of electric utility or holding company ups 1) EDP Renewables North America LLC 2) 3) 4) 5) 6) 7) 8)		int	quity

0 %

0 Btu/h

Page 8 - All Facilities FERC Form 556 **6a** Describe the primary energy input: (check one main category and, if applicable, one subcategory) Renewable resources (specify) ☐ Geothermal Biomass (specify) Fossil fuel (specify) ☐ Hydro power - river ☐ Landfill gas Coal (not waste) ☐ Hydro power - tidal ☐ Manure digester gas ☐ Fuel oil/diesel ☐ Hydro power - wave ☐ Natural gas (not waste) ☐ Sewage digester gas ☑ Solar - photovoltaic Other fossil fuel ☐ Solar - thermal ☐ Wood (describe on page 19) Other biomass (describe on page 19) ☐ Wind Other renewable resource Other (describe on page 19) Waste (specify type below in line 6b) (describe on page 19) 6b If you specified "waste" as the primary energy input in line 6a, indicate the type of waste fuel used: (check one) Waste fuel listed in 18 C.F.R. § 292.202(b) (specify one of the following) ☐ Anthracite culm produced prior to July 23, 1985 Anthracite refuse that has an average heat content of 6,000 Btu or less per pound and has an average ash content of 45 percent or more Bituminous coal refuse that has an average heat content of 9,500 Btu per pound or less and has an average ash content of 25 percent or more Top or bottom subbituminous coal produced on Federal lands or on Indian lands that has been determined to be waste by the United States Department of the Interior's Bureau of Land Management **Energy Input** (BLM) or that is located on non-Federal or non-Indian lands outside of BLM's jurisdiction, provided that the applicant shows that the latter coal is an extension of that determined by BLM to be waste Coal refuse produced on Federal lands or on Indian lands that has been determined to be waste by the ☐ BLM or that is located on non-Federal or non-Indian lands outside of BLM's jurisdiction, provided that applicant shows that the latter is an extension of that determined by BLM to be waste Lignite produced in association with the production of montan wax and lignite that becomes exposed as a result of such a mining operation Gaseous fuels (except natural gas and synthetic gas from coal) (describe on page 19) Waste natural gas from gas or oil wells (describe on page 19 how the gas meets the requirements of 18 C.F.R. § 2.400 for waste natural gas; include with your filing any materials necessary to demonstrate compliance with 18 C.F.R. § 2.400) Materials that a government agency has certified for disposal by combustion (describe on page 19) Residual heat (describe on page 19) ☐ Heat from exothermic reactions (describe on page 19) ☐ Petroleum coke ☐ Plastic materials ☐ Refinery off-gas ☐ Used rubber tires Other waste energy input that has little or no commercial value and exists in the absence of the qualifying facility industry (describe in the Miscellaneous section starting on page 19; include a discussion of the fuel's lack of commercial value and existence in the absence of the qualifying facility industry) 6c Provide the average energy input, calculated on a calendar year basis, in terms of Btu/h for the following fossil fuel energy inputs, and provide the related percentage of the total average annual energy input to the facility (18 C.F.R. § 292.202(j)). For any oil or natural gas fuel, use lower heating value (18 C.F.R. § 292.202(m)). Annual average energy Percentage of total input for specified fuel annual energy input Fuel Natural gas 0 Btu/h 0 % Oil-based fuels 0 Btu/h 0 %

Coal

delivery by completing the worksheet below. Respond to all items. If any of the parasitic loads and/olines 7b through 7e are negligible, enter zero for those lines.	or losses identified in
7a The maximum gross power production capacity at the terminals of the individual generator(s) under the most favorable anticipated design conditions	10,000 kW
7b Parasitic station power used at the facility to run equipment which is necessary and integral to the power production process (boiler feed pumps, fans/blowers, office or maintenance buildings directly related to the operation of the power generating facility, etc.). If this facility includes non-power production processes (for instance, power consumed by a cogeneration facility's thermal host), do not include any power consumed by the non-power production activities in your	
reported parasitic station power.	5 kW
7c Electrical losses in interconnection transformers	176 kW
7d Electrical losses in AC/DC conversion equipment, if any	10 kW
7e Other interconnection losses in power lines or facilities (other than transformers and AC/DC conversion equipment) between the terminals of the generator(s) and the point of interconnection	
with the utility	150 kW
7f Total deductions from gross power production capacity = 7b + 7c + 7d + 7e	341.0 kW
7g Maximum net power production capacity = 7a - 7f	9,659.0 kW

Indicate the maximum gross and maximum net electric power production capacity of the facility at the point(s) of

7h Description of facility and primary components: Describe the facility and its operation. Identify all boilers, heat recovery steam generators, prime movers (any mechanical equipment driving an electric generator), electrical generators, photovoltaic solar equipment, fuel cell equipment and/or other primary power generation equipment used in the facility. Descriptions of components should include (as applicable) specifications of the nominal capacities for mechanical output, electrical output, or steam generation of the identified equipment. For each piece of equipment identified, clearly indicate how many pieces of that type of equipment are included in the plant, and which components are normally operating or normally in standby mode. Provide a description of how the components operate as a system. Applicants for cogeneration facilities do not need to describe operations of systems that are clearly depicted on and easily understandable from a cogeneration facility's attached mass and heat balance diagram; however, such applicants should provide any necessary description needed to understand the sequential operation of the facility depicted in their mass and heat balance diagram. If additional space is needed, continue in the Miscellaneous section starting on page 19.

The facility will be a solar PV plant consisting of 39,324 polycrystalline modules of nominal 335W rating each. Total plant rating will be $13.174 \, \text{MWdc}/10 \, \text{MWac}$. Modules will be mounted to single-axis trackers.

Central inverter stations will be located at intermediate points in the PV field. Modules will be evenly distributed to the inverter stations. The total inverter nameplate rating will be 10.0MWac. Each inverter will be directly coupled to a 34.5kV step-up transformer. The transformers will be connected to a 34.5kV AC collection system, which will feed into the plant switchgear.

The plant switchgear will feed a 34.5kV transmission line, which will run overhead approximately 11.1 miles to the PacifiCorp Mile-Hi Substation.

Inside the Mile-Hi Substation, the transmission line will connect to a new bay containing a facility-owned $34.5\,kV/115\,kV$ GSU transformer, associated breakers, switching, bus, and controls.

The facility-owned components at Mile-Hi substation are considered part of the self-certified qualifying facility.



Information Required for Small Power Production Facility

If you indicated in line 1k that you are seeking qualifying small power production facility status for your facility, then you

must respond to the items on this page. Otherwise, skip page 10. Pursuant to 18 C.F.R. § 292.204(a), the power production capacity of any small power production facility, together with the power production capacity of any other small power production facilities that use the same energy resource, are owned by the same person(s) or its affiliates, and are located at the same site, may not exceed 80 megawatts. To demonstrate compliance with this size limitation, or to demonstrate that your facility is exempt from this size limitation under the Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990 (Pub. L. 101-575, 104 Stat. 2834 (1990) as amended by Pub. L. 102-46, 105 Stat. 249 (1991)), respond to lines 8a through 8e below (as applicable). 8a Identify any facilities with electrical generating equipment located within 1 mile of the electrical generating equipment of the instant facility, and for which any of the entities identified in lines 5a or 5b, or their affiliates, holds at least a 5 percent equity interest. Check here if no such facilities exist. 🏻 Certification of Compliance Maximum net power Root docket # Facility location with Size Limitations production capacity Common owner(s) (if any) (city or county, state) kW QF -1) kW 2) QF kW 3) QF Check here and continue in the Miscellaneous section starting on page 19 if additional space is needed 8b The Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990 (Incentives Act) provides exemption from the size limitations in 18 C.F.R. § 292.204(a) for certain facilities that were certified prior to 1995. Are you seeking exemption from the size limitations in 18 C.F.R. § 292.204(a) by virtue of the Incentives Act? No (skip lines 8c through 8e) Yes (continue at line 8c below) 8c Was the original notice of self-certification or application for Commission certification of the facility filed on or before December 31, 1994? Yes No 8d Did construction of the facility commence on or before December 31, 1999? Yes 8e If you answered No in line 8d, indicate whether reasonable diligence was exercised toward the completion of the facility, taking into account all factors relevant to construction? Yes No If you answered Yes, provide a brief narrative explanation in the Miscellaneous section starting on page 19 of the construction timeline (in particular, describe why construction started so long after the facility was certified) and the diligence exercised toward completion of the facility. Pursuant to 18 C.F.R. § 292.204(b), qualifying small power production facilities may use fossil fuels, in minimal Requirements Certification of Compliance amounts, for only the following purposes: ignition; start-up; testing; flame stabilization; control use; alleviation or prevention of unanticipated equipment outages; and alleviation or prevention of emergencies, directly affecting the public health, safety, or welfare, which would result from electric power outages. The amount of fossil fuels used for these purposes may not exceed 25 percent of the total energy input of the facility during the 12-month period beginning with the date the facility first produces electric energy or any calendar year thereafter. **9a** Certification of compliance with 18 C.F.R. § 292.204(b) with respect to uses of fossil fuel: Applicant certifies that the facility will use fossil fuels *exclusively* for the purposes listed above. 9b Certification of compliance with 18 C.F.R. § 292.204(b) with respect to amount of fossil fuel used annually: Applicant certifies that the amount of fossil fuel used at the facility will not, in aggregate, exceed 25 percent of the total energy input of the facility during the 12-month period beginning with the date the facility first produces electric energy or any calendar year thereafter.

Information Required for Cogeneration Facility

If you indicated in line 1k that you are seeking qualifying cogeneration facility status for your facility, then you must respond to the items on pages 11 through 13. Otherwise, skip pages 11 through 13.

to the n	terns on pages 11 tillough	13. Otherwise, skip peges 17 through										
	Pursuant to 18 C.F.R. § 292.202(c), a cogeneration facility produces electric energy and forms of useful thermal energy (such as heat or steam) used for industrial, commercial, heating, or cooling purposes, through the sequential use of energy. Pursuant to 18 C.F.R. § 292.202(s), "sequential use" of energy means the following: (1) for a topping-cycle cogeneration facility, the use of reject heat from a power production process in sufficient amounts in a thermal application or process to conform to the requirements of the operating standard contained in 18 C.F.R. § 292.205(a); or (2) for a bottoming-cycle cogeneration facility, the use of at least some reject heat from a thermal application or process for power production.											
	10a What type(s) of cogeneration technology does the facility represent? (check all that apply)											
	Topping-cycle cogeneration Bottoming-cycle cogeneration											
	10b To help demonstrate the sequential operation of the cogeneration process, and to support compliance with other requirements such as the operating and efficiency standards, include with your filing a mass and heat balance diagram depicting average annual operating conditions. This diagram must include certain items and meet certain requirements, as described below. You must check next to the description of each requirement below to certify that you have complied with these requirements.											
	Check to certify											
	compliance with indicated requirement	Requirement										
ation		Diagram must show orientation within system piping and/or ducts of all prime movers, heat recovery steam generators, boilers, electric generators, and condensers (as applicable), as well as any other primary equipment relevant to the cogeneration process.										
gener ation		Any average annual values required to be reported in lines 10b, 12a, 13a, 13b, 13d, 13f, 14a, 15b, 15d and/or 15f must be computed over the anticipated hours of operation.										
General Cogeneration Information		Diagram must specify all fuel inputs by fuel type and average annual rate in Btu/h. Fuel for supplementary firing should be specified separately and clearly labeled. All specifications of fuel inputs should use lower heating values.										
ne		Diagram must specify average gross electric output in kW or MW for each generator.										
ge		Diagram must specify average mechanical output (that is, any mechanical energy taken off of the shaft of the prime movers for purposes not directly related to electric power generation) in horsepower, if any. Typically, a cogeneration facility has no mechanical output.										
		At each point for which working fluid flow conditions are required to be specified (see below), such flow condition data must include mass flow rate (in lb/h or kg/s), temperature (in °F, R, °C or K), absolute pressure (in psia or kPa) and enthalpy (in Btu/lb or kJ/kg). Exception: For systems where the working fluid is <i>liquid only</i> (no vapor at any point in the cycle) and where the type of liquid and specific heat of that liquid are clearly indicated on the diagram or in the Miscellaneous section starting on page 19, only mass flow rate and temperature (not pressure and enthalpy) need be specified. For reference, specific heat at standard conditions for pure liquid water is approximately 1.002 Btu/ (lb*R) or 4.195 kJ/(kg*K).										
		Diagram must specify working fluid flow conditions at input to and output from each steam turbine or other expansion turbine or back-pressure turbine.										
		Diagram must specify working fluid flow conditions at delivery to and return from each thermal application.										
	, was now a	Diagram must specify working fluid flow conditions at make-up water inputs.										

EPAct 2005 cogeneration facilities: The Energy Policy Act of 2005 (EPAct 2005) established a new section 210(n) of the Public Utility Regulatory Policies Act of 1978 (PURPA), 16 USC 824a-3(n), with additional requirements for any qualifying cogeneration facility that (1) is seeking to sell electric energy pursuant to section 210 of PURPA and (2) was either not a cogeneration facility on August 8, 2005, or had not filed a self-certification or application for Commission certification of QF status on or before February 1, 2006. These requirements were implemented by the Commission in 18 C.F.R. § 292.205(d). Complete the lines below, carefully following the instructions, to demonstrate whether these additional requirements apply to your cogeneration facility and, if so, whether your facility complies with such requirements.	
	٧
for Commission certification) filed on or before February 1, 2006? Yes No	Ú
If the answer to either line 11a or 11b is Yes, then continue at line 11c below. Otherwise, if the answers to both lines 11a and 11b are No, skip to line 11e below.	. skur
11c With respect to the design and operation of the facility, have any changes been implemented on or after February 2, 2006 that affect general plant operation, affect use of thermal output, and/or increase net power production capacity from the plant's capacity on February 1, 2006?	Ø
Yes (continue at line 11d below)	
No. Your facility is not subject to the requirements of 18 C.F.R. § 292.205(d) at this time. However, it may be subject to to these requirements in the future if changes are made to the facility. At such time, the applicant would need to recertify the facility to determine eligibility. Skip lines 11d through 11j.	
a "new" cogeneration facility that would be subject to the 18 C.F.R. § 292.205(d) cogeneration requirements?	Û
Yes. Provide in the Miscellaneous section starting on page 19 a description of any relevant changes made to the facility (including the purpose of the changes) and a discussion of why the facility should not be considered a "new" cogeneration facility in light of these changes. Skip lines 11e through 11j.	
No. Applicant stipulates to the fact that it is a "new" cogeneration facility (for purposes of determining the applicability of the requirements of 18 C.F.R. § 292.205(d)) by virtue of modifications to the facility that were initiated on or after February 2, 2006. Continue below at line 11e.	
The Will electric diversity in the second diversity in	Ö
292.205(d)(2) by continuing at line 11f below.	
its understanding that it must recertify its facility in order to determine compliance with the requirements of 18 C.F.R. § 292.205(d) <i>before</i> selling energy pursuant to section 210 of PURPA in the future. Skip lines 11f through 11j.	
legisl to 5,000 kW?	Ų,
Yes, the net power production capacity is less than or equal to 5,000 kW. 18 C.F.R. § 292.205(d)(4) provides a rebuttable presumption that cogeneration facilities of 5,000 kW and smaller capacity comply with the requirements for fundamental use of the facility's energy output in 18 C.F.R. § 292.205(d)(2). Applicant certifies its understanding that, should the power production capacity of the facility increase above 5,000 kW, then the facility must be recertified to (among other things) demonstrate compliance with 18 C.F.R. § 292.205(d)(2). Skip lines 11g through 11j.	
No, the net power production capacity is greater than 5,000 kW. Demonstrate compliance with the requirements for fundamental use of the facility's energy output in 18 C.F.R. § 292.205(d)(2) by continuing on the next page at line 11g.	
	the Public Utility Regulatory Policies Act of 1978 (Pyte Na, 1o Sts. 844-34), Min undication and understanding analyting cogeneration facility that (1) is seeking to sell electric energy pursuant to section 210 of PURPA and (2) was either not a cogeneration facility on August 8, 2005, or had not filed a self-certification or application for Commission certification of cy fastus on or before February 1, 2006. These requirements were implemented by the Commission in 18 C.F.R. § 292.205(d). Complete the lines below, carefully following the instructions, to demonstrate whether these additional requirements apply to your cogeneration facility and, if so, whether your facility complies with such requirements. 11a Was your facility operating as a qualifying cogeneration facility on or before August 8, 2005? Yes. No. 1 11b Was the initial filling seeking certification of your facility (whether a notice of self-certification or an application for Commission certification) filed on or before February 1, 2006? Yes. No. 1 11c With respect to either line 11a or 11b is Yes, then continue at line 11c below. Otherwise, if the answers to both lines 11a and 11b are No, skip to line 11e below. 11c With respect to the design and operation of the facility, have any changes been implemented on or after February 2, 2006 that affect general plant operation, affect use of thermal output, and/or increase net power production capacity from the plants capacity on February 1, 2006? 12 Yes (continue at line 11d below) No. Your facility is not subject to the requirements of 18 C.F.R. § 292.205(d) at this time. However, it may be subject to to these requirements in the future if changes are made to the facility. At such time, the applicant would need to recertify the facility to determine eligibility. Skip lines 11d through 11j. 11d Does the applicant contend that the changes identified in line 11c are not so significant as to make the facility a "new" cogeneration facility that would be subject to the 18 C.F.R. § 292.205(d) cogenerati

Lines 11g through 11k below guide the applicant through the process of demonstrating compliance with the requirements for "fundamental use" of the facility's energy output. 18 C.F.R. § 292.205(d)(2). Only respond to the lines on this page if the instructions on the previous page direct you to do so. Otherwise, skip this page.

18 C.F.R. § 292.205(d)(2) requires that the electrical, thermal, chemical and mechanical output of an EPAct 2005 cogeneration facility is used fundamentally for industrial, commercial, residential or institutional purposes and is not intended fundamentally for sale to an electric utility, taking into account technological, efficiency, economic, and variable thermal energy requirements, as well as state laws applicable to sales of electric energy from a qualifying facility to its host facility. If you were directed on the previous page to respond to the items on this page, then your facility is an EPAct 2005 cogeneration facility that is subject to this "fundamental use" requirement.

The Commission's regulations provide a two-pronged approach to demonstrating compliance with the requirements for fundamental use of the facility's energy output. First, the Commission has established in 18 C.F.R. § 292.205(d)(3) a "fundamental use test" that can be used to demonstrate compliance with 18 C.F.R. § 292.205(d)(2). Under the fundamental use test, a facility is considered to comply with 18 C.F.R. § 292.205(d)(2) if at least 50 percent of the facility's total annual energy output (including electrical, thermal, chemical and mechanical energy output) is used for industrial, commercial, residential or institutional purposes.

Second, an applicant for a facility that does not pass the fundamental use test may provide a narrative explanation of and support for its contention that the facility nonetheless meets the requirement that the electrical, thermal, chemical and mechanical output of an EPAct 2005 cogeneration facility is used fundamentally for industrial, commercial, residential or institutional purposes and is not intended fundamentally for sale to an electric utility, taking into account technological, efficiency, economic, and variable thermal energy requirements, as well as state laws applicable to sales of electric energy from a qualifying facility to its host facility.

Complete lines 11g through 11j below to determine compliance with the fundamental use test in 18 C.F.R. § 292.205(d)(3). Complete lines 11g through 11j even if you do not intend to rely upon the fundamental use test to demonstrate compliance with 18 C.F.R. § 292.205(d)(2).

11g Amount of electrical, thermal, chemical and mechanical energy output (net of internal generation plant losses and parasitic loads) expected to be used annually for industrial,	MWh
commercial, residential or institutional purposes and not sold to an electric utility	IVIVI
11h Total amount of electrical, thermal, chemical and mechanical energy expected to be sold to an electric utility	MWI
11i Percentage of total annual energy output expected to be used for industrial, commercial, residential or institutional purposes and not sold to a utility	
= 100 * 11g /(11g + 11h)	0 %

11j Is the response in line 11i greater than or equal to 50 percent?

Yes. Your facility complies with 18 C.F.R. § 292.205(d)(2) by virtue of passing the fundamental use test provided in 18 C.F.R. § 292.205(d)(3). Applicant certifies its understanding that, if it is to rely upon passing the fundamental use test as a basis for complying with 18 C.F.R. § 292.205(d)(2), then the facility must comply with the fundamental use test both in the 12-month period beginning with the date the facility first produces electric energy, and in all subsequent calendar years.

No. Your facility does not pass the fundamental use test. Instead, you must provide in the Miscellaneous section starting on page 19 a narrative explanation of and support for why your facility meets the requirement that the electrical, thermal, chemical and mechanical output of an EPAct 2005 cogeneration facility is used fundamentally for industrial, commercial, residential or institutional purposes and is not intended fundamentally for sale to an electric utility, taking into account technological, efficiency, economic, and variable thermal energy requirements, as well as state laws applicable to sales of electric energy from a QF to its host facility. Applicants providing a narrative explanation of why their facility should be found to comply with 18 C.F.R. § 292.205(d)(2) in spite of non-compliance with the fundamental use test may want to review paragraphs 47 through 61 of Order No. 671 (accessible from the Commission's QF website at www.ferc.gov/QF), which provide discussion of the facts and circumstances that may support their

comply with 18 C.F.R. § 292.205(d)(2) in spite of non-compliance with the fundamental use test may want to review paragraphs 47 through 61 of Order No. 671 (accessible from the Commission's QF website at www.ferc.gov/QF), which provide discussion of the facts and circumstances that may support their explanation. Applicant should also note that the percentage reported above will establish the standard that that facility must comply with, both for the 12-month period beginning with the date the facility first produces electric energy, and in all subsequent calendar years. See Order No. 671 at paragraph 51. As such, the applicant should make sure that it reports appropriate values on lines 11g and 11h above to serve as the relevant annual standard, taking into account expected variations in production conditions.



thermal output attributable to use (net of

Usefulness of Topping-Cycle Thermal Output

Information Required for Topping-Cycle Cogeneration Facility

If you indicated in line 10a that your facility represents topping-cycle cogeneration technology, then you must respond to the items on pages 14 and 15. Otherwise, skip pages 14 and 15.

The thermal energy output of a topping-cycle cogeneration facility is the net energy made available to an industrial or commercial process or used in a heating or cooling application. Pursuant to sections 292.202(c), (d) and (h) of the Commission's regulations (18 C.F.R. §§ 292.202(c), (d) and (h)), the thermal energy output of a qualifying topping-cycle cogeneration facility must be useful. In connection with this requirement, describe the thermal output of the topping-cycle cogeneration facility by responding to lines 12a and 12b below.

12a Identify and describe each thermal host, and specify the annual average rate of thermal output made available to each host for each use. For hosts with multiple uses of thermal output, provide the data for each use *in separate rows*.

Average annual rate of

	Name of entity (thermal host) taking thermal output	Thermal host's relationship to facility; Thermal host's use of thermal output	heat contained in process return or make-up water)
		Select thermal host's relationship to facility	
1)		Select thermal host's use of thermal output	Btu/h
		Select thermal host's relationship to facility	
2)		Select thermal host's use of thermal output	Btu/h
		Select thermal host's relationship to facility	
3)		Select thermal host's use of thermal output	Btu/h
		Select thermal host's relationship to facility	
4)		Select thermal host's use of thermal output	Btu/h
		Select thermal host's relationship to facility	
5)		Select thermal host's use of thermal output	Btu/h
		Select thermal host's relationship to facility	
6)		Select thermal host's use of thermal output	Btu/h

Check here and continue in the Miscellaneous section starting on page 19 if additional space is needed

12b Demonstration of usefulness of thermal output: At a minimum, provide a brief description of each use of the thermal output identified above. In some cases, this brief description is sufficient to demonstrate usefulness. However, if your facility's use of thermal output is not common, and/or if the usefulness of such thermal output is not reasonably clear, then you must provide additional details as necessary to demonstrate usefulness. Your application may be rejected and/or additional information may be required if an insufficient showing of usefulness is made. (Exception: If you have previously received a Commission certification approving a specific use of thermal output related to the instant facility, then you need only provide a brief description of that use and a reference by date and docket number to the order certifying your facility with the indicated use. Such exemption may not be used if any change creates a material deviation from the previously authorized use.) If additional space is needed, continue in the Miscellaneous section starting on page 19.



m 556 Page 15 - Topping-Cyc	le Cogeneration Facilities
Applicants for facilities representing topping-cycle technology must demonstrate compliancycle operating standard and, if applicable, efficiency standard. Section 292.205(a)(1) of the regulations (18 C.F.R. § 292.205(a)(1)) establishes the operating standard for topping-cycle the useful thermal energy output must be no less than 5 percent of the total energy output (18 C.F.R. § 292.205(a)(2)) establishes the efficiency standard for topping-cycle cogeneration installation commenced on or after March 13, 1980: the useful power output of the facility thermal energy output must (A) be no less than 42.5 percent of the total energy input of naticility; and (B) if the useful thermal energy output is less than 15 percent of the total energy be no less than 45 percent of the total energy input of natural gas and oil to the facility. To compliance with the topping-cycle operating and/or efficiency standards, or to demonstrate exempt from the efficiency standard based on the date that installation commenced, responsible below.	commission's cogeneration facilities: (at. Section 292.205(a)(2) on facilities for which plus one-half the useful atural gas and oil to the gy output of the facility, o demonstrate ate that your facility is
If you indicated in line 10a that your facility represents both topping-cycle and bottoming-technology, then respond to lines 13a through 13l below considering only the energy input attributable to the topping-cycle portion of your facility. Your mass and heat balance diag which mass and energy flow values and system components are for which portion (toppin cogeneration system. 13a Indicate the annual average rate of useful thermal energy output made available	uts and outputs yram must make clear
to the host(s), net of any heat contained in condensate return or make-up water	Btu/h
13b Indicate the annual average rate of net electrical energy output	LIA
13c Multiply line 13b by 3,412 to convert from kW to Btu/h	kW 0 Btu/h
13d Indicate the annual average rate of mechanical energy output taken directly off of the shaft of a prime mover for purposes not directly related to power production (this value is usually zero)	hp
13e Multiply line 13d by 2,544 to convert from hp to Btu/h	0 Btu/h
13f Indicate the annual average rate of energy input from natural gas and oil	Btu/h
13g Topping-cycle operating value = 100 * 13a / (13a + 13c + 13e)	0 %
13h Topping-cycle efficiency value = 100 * (0.5*13a + 13c + 13e) / 13f	0.%
13i Compliance with operating standard: Is the operating value shown in line 13g greate	er than or equal to 5%?
Yes (complies with operating standard) No (does not comply with a	
13j Did installation of the facility in its current form commence on or after March 13, 1980	0?
Yes. Your facility is subject to the efficiency requirements of 18 C.F.R. § 292.205(a) compliance with the efficiency requirement by responding to line 13k or 13l, as a)(2). Demonstrate pplicable, below.
No. Your facility is exempt from the efficiency standard. Skip lines 13k and 13l.	
13k Compliance with efficiency standard (for low operating value): If the operating value than 15%, then indicate below whether the efficiency value shown in line 13h greater than	e shown in line 13g is less in or equal to 45%:
Yes (complies with efficiency standard) No (does not comply with	efficiency standard)
13l Compliance with efficiency standard (for high operating value): If the operating value greater than or equal to 15%, then indicate below whether the efficiency value shown in	e shown in line 13g is line 13h is greater than or

Yes (complies with efficiency standard)

☐ No (does not comply with efficiency standard)

Information Required for Bottoming-Cycle Cogeneration Facility

If you indicated in line 10a that your facility represents bottoming-cycle cogeneration technology, then you must respond

to the items on pages 16 and 17. Otherwise, skip pages 16 and 17. The thermal energy output of a bottoming-cycle cogeneration facility is the energy related to the process(es) from which at least some of the reject heat is then used for power production. Pursuant to sections 292.202(c) and (e) of the Commission's regulations (18 C.F.R. § 292.202(c) and (e)), the thermal energy output of a qualifying bottomingcycle cogeneration facility must be useful. In connection with this requirement, describe the process(es) from which at least some of the reject heat is used for power production by responding to lines 14a and 14b below. 14a Identify and describe each thermal host and each bottoming-cycle cogeneration process engaged in by each host. For hosts with multiple bottoming-cycle cogeneration processes, provide the data for each process in separate rows. Has the energy input to the thermal host been Name of entity (thermal host) augmented for purposes performing the process from of increasing power which at least some of the production capacity? Thermal host's relationship to facility; reject heat is used for power (if Yes, describe on p. 19) Thermal host's process type production Select thermal host's relationship to facility No Yes 1) Select thermal host's process type Select thermal host's relationship to facility Yes No 📗 2) Select thermal host's process type Select thermal host's relationship to facility Yes No | 3) Select thermal host's process type Check here and continue in the Miscellaneous section starting on page 19 if additional space is needed **14b** Demonstration of usefulness of thermal output: At a minimum, provide a brief description of each process identified above. In some cases, this brief description is sufficient to demonstrate usefulness. However, if your facility's process is not common, and/or if the usefulness of such thermal output is not reasonably clear, then you must provide additional details as necessary to demonstrate usefulness. Your application may be rejected and/or additional information may be required if an insufficient showing of usefulness is made. (Exception: If you have previously received a Commission certification approving a specific bottoming-cycle process related to the instant facility, then you need only provide a brief description of that process and a reference by date and docket number to the order certifying your facility with the indicated process. Such exemption may not be used if any material changes to the process have been made.) If additional space is needed, continue in the Miscellaneous section starting on page 19.

No (does not comply with efficiency standard)

than or equal to 45%:

Yes (complies with efficiency standard)

111 330	-Cycle Cogeneration Facilities
Applicants for facilities representing bottoming-cycle technology and for which installation March 13, 1990 must demonstrate compliance with the bottoming-cycle efficiency start the Commission's regulations (18 C.F.R. § 292.205(b)) establishes the efficiency standard cogeneration facilities: the useful power output of the facility must be no less than 45 of natural gas and oil for supplementary firing. To demonstrate compliance with the b standard (if applicable), or to demonstrate that your facility is exempt from this standard installation of the facility began, respond to lines 15a through 15h below.	d for bottoming-cycle percent of the energy input ottoming-cycle efficiency d based on the date that
If you indicated in line 10a that your facility represents <i>both</i> topping-cycle and bottom technology, then respond to lines 15a through 15h below considering only the energy attributable to the bottoming-cycle portion of your facility. Your mass and heat balance which mass and energy flow values and system components are for which portion of the (topping or bottoming).	inputs and outputs te diagram must make clear
15a Did installation of the facility in its current form commence on or after March 13,	1980?
Yes. Your facility is subject to the efficiency requirement of 18 C.F.R. § 292.205 with the efficiency requirement by responding to lines 15b through 15h below No. Your facility is exempt from the efficiency standard. Skip the rest of page	(b). Demonstrate compliance v.
V.A.	
15b Indicate the annual average rate of net electrical energy output	kW
15c Multiply line 15b by 3,412 to convert from kW to Btu/h	0 Btu/h
15d Indicate the annual average rate of mechanical energy output taken directly off of the shaft of a prime mover for purposes not directly related to power production (this value is usually zero)	hp
15e Multiply line 15d by 2,544 to convert from hp to Btu/h	0 Btu/h
15f Indicate the annual average rate of supplementary energy input from natural gas or oil	Btu/h
15g Bottoming-cycle efficiency value = 100 * (15c + 15e) / 15f	0 %
15h Compliance with efficiency standard: Indicate below whether the efficiency value	e shown in line 15g is greater

П

Commission Staff Use Only:

Certificate of Completeness, Accuracy and Authority

Applicant must certify compliance with and understanding of filing requirements by checking next to each item below and signing at the bottom of this section. Forms with incomplete Certificates of Completeness, Accuracy and Authority will be

rejected by the Secretary of the Commission. Signer identified below certifies the following: (check all items and applicable subitems) He or she has read the filing, including any information contained in any attached documents, such as cogeneration mass and heat balance diagrams, and any information contained in the Miscellaneous section starting on page 19, and knows its contents. He or she has provided all of the required information for certification, and the provided information is true as stated, to the best of his or her knowledge and holief to the best of his or her knowledge and belief. He or she possess full power and authority to sign the filing; as required by Rule 2005(a)(3) of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2005(a)(3)), he or she is one of the following: (check one) The person on whose behalf the filing is made An officer of the corporation, trust, association, or other organized group on behalf of which the filing is made An officer, agent, or employe of the governmental authority, agency, or instrumentality on behalf of which the filing is made A representative qualified to practice before the Commission under Rule 2101 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2101) and who possesses authority to sign He or she has reviewed all automatic calculations and agrees with their results, unless otherwise noted in the Miscellaneous section starting on page 19. He or she has provided a copy of this Form 556 and all attachments to the utilities with which the facility will interconnect and transact (see lines 4a through 4d), as well as to the regulatory authorities of the states in which the facility and those utilities reside. See the Required Notice to Public Utilities and State Regulatory Authorities section on page 3 for more information. Provide your signature, address and signature date below. Rule 2005(c) of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2005(c)) provides that persons filing their documents electronically may use typed characters representing his or her name to sign the filed documents. A person filing this document electronically should sign (by typing his or her name) in the space provided below. Your address Date Your Signature 808 Travis Street #700 Houston, TX 77002 9/6/2016 Leslie A. Freiman **Audit Notes**

Page 19 - All Facilities

FERC Form 556

Miscellaneous

Use this space to provide any information for which there was not sufficient space in the previous sections of the form to provide. For each such item of information clearly identify the line number that the information belongs to. You may also use this space to provide any additional information you believe is relevant to the certification of your facility.

Your response below is not limited to one page. Additional page(s) will automatically be inserted into this form if the length of your response exceeds the space on this page. Use as many pages as you require.

Section 1(1) continued:

Blue Marmot VI LLC (Applicant) hereby updates its prior self-certification of qualifying facility status to reflect an anticipated installation date of September 30, 2019 and commercial operation date of November 30, 2019. In addition, Applicant also updates the facility description and rating information provided in section 7.

EXHIBIT B REQUIRED FACILITY DOCUMENTS

Sellers Generation Interconnection Agreement

Transmission Service Agreement with PacifiCorp

Purchase option agreement

Conditional Use Permit issued by Lake County

Any additional permits that might be required by Lake County or Oregon Department of Environmental Quality, including access permit, building and electric permits, and storm water prevention permit

FERC Qualifying Facility self-certification

EXHIBIT C START-UP TESTING

VISUAL AND MECHANICAL INSPECTIONS

INVERTER COMMISSIONING

ELECTRICAL OPERATION TESTS

SYSTEM MONITORING VERIFICATION

TRACKER VERIFICATION

INFRARED SCANS

BLOCK TESTING

72-HOUR FUNCTIONAL TEST

GRID MATCH TEST

POWER CHARACTERIZATION

REVENUE METER VERIFICATION

REACTIVE POWER TEST

POWER OUTPUT TEST - PLANT PERFORMANCE AND ACCEPTANCE

EXHIBIT D SCHEDULE

Sheet No. 201-1

SCHEDULE 201 QUALIFYING FACILITY 10 MW or LESS AVOIDED COST POWER PURCHASE INFORMATION

PURPOSE

To provide information about Standard Avoided Costs and Renewable Avoided Costs, Standard Power Purchase Agreements (PPA) and Negotiated PPAs, power purchase prices and price options for power delivered by a Qualifying Facility (QF) to the Company with nameplate capacity of 10,000 kW (10MW) or less.

AVAILABLE

To owners of QFs making sales of electricity to the Company in the State of Oregon (Seller).

APPLICABLE

For power purchased from small power production or cogeneration facilities that are QFs as defined in 18 Code of Federal Regulations (CFR) Section 292, that meet the eligibility requirements described herein and where the energy is delivered to the Company's system and made available for Company purchase pursuant to a Standard PPA.

ESTABLISHING CREDITWORTHINESS

The Seller must establish creditworthiness prior to service under this schedule. For a Standard PPA, a Seller may establish creditworthiness with a written acknowledgment that it is current on all existing debt obligations and that it was not a debtor in a bankruptcy proceeding within the preceding 24 months. If the Seller is not able to establish creditworthiness, the Seller must provide security deemed sufficient by the Company as set forth in the Standard PPA.

POWER PURCHASE INFORMATION

A Seller may call the Power Production Coordinator at (503) 464-8000 to obtain more information about being a Seller or how to apply for service under this schedule.

PPA

In accordance with terms set forth in this schedule and the Commission's Rules as applicable, the Company will purchase any Energy in excess of station service (power necessary to produce generation) and amounts attributable to conversion losses, which are made available from the Seller.

A Seller must execute a PPA with the Company prior to delivery of power to the Company. The agreement will have a term of up to 20 years as selected by the QF.

A QF with a nameplate capacity rating of 10 MW or less as defined herein may elect the option of a Standard PPA.

PPA (Continued)

Any Seller may elect to negotiate a PPA with the Company. Such negotiation will comply with the requirements of the Federal Energy Regulatory Commission (FERC), and the Commission including the guidelines in Order No. 07-360, and Schedule 202. Negotiations for power purchase pricing will be based on either the filed Standard Avoided Costs or Renewable Avoided Costs in effect at that time.

STANDARD PPA (Nameplate capacity of 10 MW or less)

A Seller choosing a Standard PPA will complete all informational and price option selection requirements in the applicable Standard PPA and submit the executed Agreement to the Company prior to service under this schedule. The Standard PPA is available at www.portlandgeneral.com. The available Standard PPAs are:

- Standard In-System Non-Variable Power Purchase Agreement
- Standard Off-System Non-Variable Power Purchase Agreement
- Standard In-System Variable Power Purchase Agreement
- Standard Off-System Variable Power Purchase Agreement
- Standard Renewable In-System Non-Variable Power Purchase Agreement
- Standard Renewable Off-System Non-Variable Power Purchase Agreement
- Standard Renewable In-System Variable Power Purchase Agreement
- Standard Renewable Off-System Variable Power Purchase Agreement

The Standard PPAs applicable to variable resources are available only to QFs utilizing wind, solar or run of river hydro as the primary motive force.

GUIDELINES FOR 10 MW OR LESS FACILITIES ELECTING STANDARD PPA

To execute the Standard PPA the Seller must complete all of the general project information requested in the applicable Standard PPA.

When all information required in the Standard PPA has been received in writing from the Seller, the Company will respond within 15 business days with a draft Standard PPA.

The Seller may request in writing that the Company prepare a final draft Standard PPA. The Company will respond to this request within 15 business days. In connection with such request, the QF must provide the Company with any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft Standard PPA.

When both parties are in full agreement as to all terms and conditions of the draft Standard PPA, the Company will prepare and forward to the Seller a final executable version of the agreement within 15 business days. Following the Company's execution, an executed copy will be returned to the Seller. Prices and other terms and conditions in the PPA will not be final and binding until the Standard PPA has been executed by both parties.

OFF-SYSTEM PPA

A Seller with a facility that interconnects with an electric system other than the Company's electric system may enter into a PPA with the Company after following the applicable Standard or Negotiated PPA guidelines and making the arrangements necessary for transmission of power to the Company's system.

BASIS FOR POWER PURCHASE PRICE

AVOIDED COST SUMMARY

The power purchase prices are based on either the Company's Standard Avoided Costs or Renewable Avoided Costs in effect at the time the agreement is executed. Avoided Costs are defined in 18 CFR 292.101(6) as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."

Monthly On-Peak prices are included in both the Standard Avoided Costs as listed in Tables 1a, 2a, and 3a and Renewable Avoided Costs as listed in Tables 4a, 5a, and 6a. Monthly Off-Peak prices are included in both the Standard Avoided Costs as listed in Tables 1b, 2b, and 3b and Renewable Avoided Costs as listed in Tables 4b, 5b, and 6b.

ON-PEAK PERIOD

The On-Peak period is 6:00 a.m. until 10:00 p.m., Monday through Saturday.

OFF-PEAK PERIOD

The Off-Peak period is 10:00 p.m. until 6:00 a.m., Monday through Saturday, and all day on Sunday.

Standard Avoided Costs are based on forward market price estimates through the Resource Sufficiency Period, the period of time during which the Company's Standard Avoided Costs are associated with incremental purchases of Energy and capacity from the market. For the Resource Deficiency Period, the Standard Avoided Costs reflect the fully allocated costs of a natural gas fueled combined cycle combustion turbine (CCCT) including fuel and capital costs. The CCCT Avoided Costs are based on the variable cost of Energy plus capitalized Energy costs at a 93% capacity factor based on a natural gas price forecast, with prices modified for shrinkage and transportation costs.

Renewable Avoided Costs are based on forward market price estimates through the Renewable Resource Sufficiency Period, the period of time during which the Company's Renewable Avoided Costs are associated with incremental purchases of energy and capacity from the market. For the Renewable Resource Deficiency Period, the Renewable Avoided Costs reflect the fully allocated costs of a wind plant including capital costs.

PRICING FOR STANDARD PPA

Pricing represents the purchase price per MWh the Company will pay for electricity delivered to a Point of Delivery (POD) within the Company's service territory pursuant to a Standard PPA up to the nameplate rating of the QF in any hour. Any Energy delivered in excess of the nameplate rating will be purchased at the applicable Off-Peak Prices for the selected pricing option.

The Standard PPA pricing will be based on either the Standard or Renewable Avoided Costs in effect at the time the agreement is executed.

The Company will pay the Seller either the Off-Peak Standard Avoided Cost pursuant to Tables 1b, 2b, or 3b or the Off-Peak Renewable Avoided Costs pursuant to Tables 4b, 5b, or 6b for: (a) all Net Output delivered prior to the Commercial Operation Date; (b) all Net Output deliveries greater than Maximum Net Output in any PPA year; (c) any generation subject to and as adjusted by the provisions of Section 4.3 of the Standard PPA; (d) Net Output delivered in the Off-Peak Period; and (e) deliveries above the nameplate capacity in any hour. The Company will pay the Seller either the On-Peak Standard Avoided Cost pursuant to Tables 1a, 2a, or 3a or the On-Peak Renewable Avoided Costs pursuant to Tables 4a, 5a, or 6a for all other Net Output. (See the PPA for defined terms.)

1) Standard Fixed Price Option

The Standard Fixed Price Option is based on Standard Avoided Costs including forecasted natural gas prices. It is available to all QFs.

This option is available for a maximum term of 15 years. Prices will be as established at the time the Standard PPA is executed and will be equal to the Standard Avoided Costs in Tables 1a and 1b, 2a and 2b, or 3a and 3c, depending on the type of QF, effective at execution. QFs using any resource type other than wind and solar are assumed to be Base Load QFs.

Prices paid to the Seller under the Standard Fixed Price Option include adjustments for the capacity contribution of the QF resource type relative to that of the avoided proxy resource. Both the Base Load QF resources (Tables 1a and 1b) and the avoided proxy resource, the basis used to determine Standard Avoided Costs for the Standard Fixed Price Option, are assumed to have a capacity contribution to peak of 100%. The capacity contribution for Wind QF resources (Tables 2a and 2b) is assumed to be 5%. The capacity contribution for Solar QF resources (Tables 3a and 3b) is assumed to be 5%.

Prices paid to the Seller under the Standard Fixed Price Option for Wind QFs (Tables 2a and 2b) include a reduction for the wind integration costs in Table 7. However, if the Wind QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the wind integration charges in Table 7, in addition to the prices listed in Tables 2a and 2b, for a net-zero effect.

Sheet No. 201-5

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

Sellers with PPAs exceeding 15 years will receive pricing equal to the Mid-C Index Price for all years up to five in excess of the initial 15.

					Т.	ABLE 1a			,			
					Avo	ided Cos	ts					
			St	andard F	ixed Pric	e Option	for Base	Load QF				
				0	n-Peak F	orecast ((\$/MWH)					
	_			_	-	_		<u> </u>	_	_		
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	28.21	22.46	15.61	14.71	12.46	16.96	23.96	26.96	24.96	23.71	26.71	31.46
2017	29.96	28.21	24.71	20.96	19.46	20.46	27.96	30.96	29.46	27.71	28.71	33.71
2018	31.71	31.11	28.11	22.13	21.28	21.28	29.93	33.37	30.63	28.61	31.86	35.71
2019	33.94	31.95	27.97	23.70	22.00	23.13	31.67	35.08	33.37	31.38	32.52	38.21
2020	35.74	33.64	29.45	24.95	23.15	24.35	33.34	36.94	35.14	33.04	34.24	40.24
2021	67.43	67.34	65.41	64.69	64.41	64.50	64.61	64.73	64.84	65.48	68.60	68.72
2022	69.01	68.84	68.08	67.13	66.81	66.91	67.04	67.17	67.29	67.83	71.38	71.70
2023	71.95	71.76	70.39	69.19	69.07	69.18	69.31	69.45	69.58	70.12	73.56	73.70
2024	74.17	73.85	72.67	71.29	71.10	71.21	71.35	71.50	71.63	72.20	76.49	76.64
2025	77.19	77.30	75.84	74.88	75.02	75.14	75.30	75.47	75.62	75.80	82.57	82.89
2026	85.18	85.30	82.77	81.28	81.22	81.36	81.56	81.74	81.90	82.36	89.02	88.72
2027	86.85	86.76	85.14	83.12	82.89	83.03	83.00	83.32	83.46	83.97	91.39	91.15
2028	89.32	89.31	87.96	85.46	85.30	85.46	85.31	85.64	85.95	86.65	94.66	93.55
2029	94.06	93.99	91.23	88.74	87.97	88.15	87.71	88.06	88.61	89.34	98.37	98.11
2030	97.60	97.54	94.87	92.62	92.40	92.57	92.61	93.00	93.12	93.68	102.42	102.70
2031	99.56	99.50	96.78	94.48	94.26	94.43	94.47	94.87	94.99	95.56	104.47	104.76
2032	103.85	103.80	100.5 7	98.18	97.96	98.15	98.23	98.65	98.76	99.36	108.86	109.41
2033	106.56	106.51	103.17	100.72	100.50	100.69	100.78	101.21	101.32	101.93	111.67	112.26
2034	109.12	109.07	105.60	103.10	102.88	103.08	103.17	103.61	103.72	104.35	114.33	114.96
2035	111.55	111.51	107.91	105.35	105.12	105.33	105.43	105.89	105.99	106.63	116.87	117.54
2036	113.85	113.80	110.14	107.53	107.30	107.51	107.60	108.07	108.18	108.83	119.27	119.95
2037	116.50	116.45	112.72	110.06	109.82	110.04	110.14	110.61	110.73	111.39	122.03	122.73
2038	119.08	119.03	115.22	112.51	112.27	112.49	112.59	113.08	113.19	113.87	124.71	125.42
2039	121.47	121.42	117.54	114.77	114.53	114.75	114.85	115.35	115.47	116.15	127.21	127.93
2040	124.25	124.20	120.25	117.43	117.18	117.41	117.51	118.02	118.14	118.84	130.10	130.85
2041	126.72	126.67	122.64	119.76	119.51	119.74	119.85	120.36	120.49	121.20	132.68	133.44

					T/	BLE 1b						
					Avoi	ded Cost	s					
			Sta	ndard Fi	xed Price	Option 1	for Base	Load QF				
				Of	ff-Peak Fo	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	25.61	20.71	13.96	11.41	6.31	10.11	15.71	20.96	20.96	21.21	23.46	26.71
2017	25.71	24.21	22.21	15.71	13.71	12.71	19.71	25.21	25.46	24.71	25.71	27.96
2018	26.17	28.12	25.56	19.46	14.68	12.54	19.71	27.04	26.93	25.35	28.20	30.62
2019	29.84	28.09	25.75	18.15	15.81	14.64	22.83	29.26	29.55	28.67	29.84	32.47
2020	31.75	29:88	27.38	19.28	16.79	15.54	24.27	31.12	31.43	30.50	31.75	34.55
2021	28.88	28.79	26.86	26.15	25.87	25.95	26.07	26.19	26.30	26.94	30.06	30.18
2022	29.73	29.56	28.79	27.85	27.53	27.63	27.75	27.88	28.00	28.54	32.09	32.42
2023	31.78	31.59	30.21	29.01	28.90	29.00	29.14	29.27	29.40	29.95	33.38	33.52
2024	33.48	33.16	31.98	30.60	30.41	30.52	30.66	30.81	30.95	31.51	35.80	35.96
2025	35.58	35.69	34.24	33.27	33.42	33.53	33.70	33.86	34.01	34.19	40.97	41.28
2026	42.77	42.89	40.36	38.87	38.81	38.95	39.15	39.34	39.50	39.95	46.62	46.31
2027	43.63	43.54	41.91	39.89	39.66	39.80	39.77	40.09	40.24	40.74	48.16	47.92
2028	45.26	45.25	43.90	41.40	41.23	41.40	41.25	41.58	41.89	42.59	50.60	49.48
2029	49.15	49.08	46.32	43.83	43.06	43.24	42.80	43.15	43.70	44.43	53.46	53.20
2030	51.82	51.76	49.09	46.84	46.62	46.79	46.83	47.22	47.34	47.90	56.64	56.92
2031	52.90	52.84	50.11	47.82	47.59	47.77	47.81	48.21	48.33	48.90	57.81	58.10
2032	56.59	56.54	53.31	50.92	50.70	50.89	50.97	51.39	51.50	52.10	61.60	62.15
2033	58.08	58.03	54.69	52.24	52.02	52.21	52.30	52.73	52.84	53.45	63.19	63.78
2034	59.54	59.50	56.03	53.52	53.30	53.50	53.59	54.04	54.15	54.77	64.76	65.39
2035	61.18	61.14	57.54	54.98	54.75	54.96	55.06	55.52	55.62	56.26	66.50	67.17
2036	62.67	62.62	58.96	56.35	56.12	56.33	56.43	56.89	57.00	57.65	68.09	68.78
2037	64.17	64.12	60.39	57.73	57.49	57.71	57.80	58.28	58.39	59.06	69.69	70.39
2038	65.73	65.69	61.88	59.17	58.93	59.15	59.25	59.73	59.85	60.52	71.37	72.08
2039	67.09	67.04	63.16	60.40	60.15	60.38	60.48	60.98	61.09	61.78	72.83	73.56
2040	68.83	68.78	64.83	62.01	61.76	61.99	62.09	62.60	62.72	63.42	74.68	75.42
2041	70.23	70.17	66.14	63.27	63.02	63.25	63.36	63.87	63.99	64.71	76.19	76.95

	•				TA	BLE 2a						
					Avoi	ded Cost	s					
				Standard	Fixed Pr	ice Optic	n for Wi	nd QF				
				Or	n-Peak Fo	orecast (S	5/MWH)					
										0.1		D
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	24.37	18.62	1 1 .77	10.87	8.62	13.12	20.12	23.12	21.12	19.87	22.87	27.62
2017	26.05	24.30	20.80	17.05	15.55	16.55	24.05	27.05	25.55	23.80	24.80	29.80
2018	27.72	27.12	24.12	18.14	17.29	17.29	25.94	29.38	26.64	24.62	27.87	31.72
2019	29.87	27.88	23.90	19.63	17.93	19.06	27.60	31.01	29.30	27.31	28.45	34.14
2020	31.59	29.49	25.30	20.80	19.00	20.20	29.19	32.79	30.99	28.89	30.09	36.09
2021	30.68	30.59	28.66	27.94	27.66	27.75	27.87	27.99	28.10	28.74	31.86	31.98
2022	31.56	31.39	30.62	29.68	29.36	29.46	29.59	29.72	29.84	30.38	33.93	34.25
2023	33.67	33.48	32.11	30.91	30.79	30.90	31.03	31.17	31.30	31.84	35.28	35.42
2024	35.38	35.06	33.88	32.49	32.30	32.42	32.56	32.70	32.84	33.40	37.70	37.85
2025	37.53	37.64	36.18	35.22	35.36	35.48	35.64	35.81	35.96	36.14	42.91	43.23
2026	44.75	44.87	42.35	40.86	40.79	40.94	41.13	41.32	41.48	41.94	48.60	48.29
2027	45.65	45.56	43.93	41.91	41.68	41.82	41.79	42.12	42.26	42.76	50.18	49.94
2028	47.32	47.31	45.96	43.46	43.30	43.46	43.31	43.64	43.95	44.65	52.66	51.55
2029	51.25	51.18	48.43	45.94	45.16	45.34	44.90	45.25	45.80	46.53	55.57	55.30
2030	53.96	53.90	51.23	48.98	48.76	48.93	48.97	49.36	49.48	50.04	58.78	59.06
2031	55.08	55.02	52.29	50.00	49.77	49.95	49.99	50.38	50.51	51.08	59.99	60.28
2032	58.77	58.72	55.49	53.10	52.88	53.07	53.15	53.57	53.68	54.28	63.78	64.33
2033	60.35	60.30	56.96	54.51	54.29	54.49	54.57	55.00	55.11	55.72	65.46	66.05
2034	61.88	61.83	58.36	55.86	55.63	55.84	55.93	56.37	56.48	57.10	67.09	67.72
2035	63.54	63.49	59.90	57.34	57.11	57.32	57.42	57.87	57.98	58.62	68.86	69.53
2036	65.04	65.00	61.33	58.72	58.49	58.70	58.80	59.27	59.38	60.03	70.46	71.15
2037	66.61	66.57	62.83	60.17	59.93	60.15	60.25	60.73	60.84	61.50	72.14	72.84
2038	68.23	68.18	64.37	61.66	61.42	61.64	61.74	62.23	62.34	63.02	73.86	74.57
2039	69.64	69.59	65.71	62.94	62.70	62.92	63.03	63.52	63.64	64.33	75.38	76.11
2040	71.42	71.37	67.41	64.60	64.35	64.58	64.68	65.18	65.30	66.00	77.27	78.01
2040	71.42	72.82	68.79	65.92	65.66	65.90	66.00	66.52	66.64	67.35	78.84	79.59

					TA	ABLE 2b						
						ded Cost	.s					
				Standard	l Fixed P	rice Optic	n for Wi	nd QF				
				0	ff-Peak F	orecast (\$/MWH)			.,		
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	21.77	16.87	10.12	7.57	2.47	6.27	11.87	17.12	17.12	17.37	19.62	22.87
2017	21.80	20.30	18.30	11.80	9.80	8.80	15.80	21.30	21.55	20.80	21.80	24.05
2018	22.18	24.13	21.57	15.47	10.69	8.55	15.72	23.05	22.94	21.36	24.21	26.63
2019	25.77	24.02	21.68	14.08	11.74	10.57	18.76	25.19	25.48	24.60	25.77	28.40
2020	27.60	25.73	23.23	15.13	12.64	11.39	20.12	26.97	27.28	26.35	27.60	30.40
2021	24.65	24.56	22.63	21.92	21.64	21.72	21.84	21.96	22.07	22.71	25.83	25.95
2022	25.42	25.25	24.48	23.54	23.22	23.32	23.44	23.57	23.69	24.23	27.78	28.11
2023	27.39	27.20	25.82	24.62	24.51	24.61	24.75	24.88	25.01	25.56	28.99	29.13
2024	29.01	28.69	27.51	26.13	25.94	26.05	26.19	26.34	26.48	27.04	31.33	31.49
2025	31.02	31.13	29.68	28.71	28.86	28.97	29.14	29.30	29.45	29.63	36.41	36.72
2026	38.12	38.24	35.71	34.22	34.16	34.30	34.50	34.69	34.85	35.30	41.97	41.66
2027	38.89	38.80	37.17	35.15	34.92	35.06	35.03	35.35	35.50	36.00	43.42	43.18
2028	40.43	40.42	39.07	36.57	36.40	36.57	36.42	36.75	37.06	37.76	45.77	44.65
2029	44.23	44.16	41.40	38.91	38.14	38.32	3 7 .88	38.23	38.78	39.51	48.54	48.28
2030	46.80	46. 7 4	44.07	41.82	41.60	41.77	41.81	42.20	42.32	42.88	51.62	51.90
2031	47.78	47.72	44.99	42.70	42.47	42.65	42.69	43.09	43.21	43.78	52.69	52.98
2032	51.38	51.33	48.10	45.71	45.49	45.68	45.76	46.18	46.29	46.89	56.39	56.94
2033	52.77	52.72	49.38	46.93	46.71	46.90	46.99	47.42	47.53	48.14	57.88	58.47
2034	54.12	54.08	50.61	48.10	47.88	48.08	48.17	48.62	48.73	49.35	59.34	59.97
2035	55.66	55.62	52.02	49.46	49.23	49.44	49.54	50.00	50.10	50.74	60.98	61.65
2036	57.04	56.99	53.33	50.72	50.49	50.70	50.80	51.26	51.37	52.02	62.46	63.15
2037	58.43	58.38	54.65	51.99	51.75	51.97	52.06	52.54	52.65	53.32	63.95	64.65
2038	59.88	59.84	56.03	53.32	53.08	53.30	53.40	53.88	54.00	54.67	65.52	66.23
2039	61.13	61.08	57.20	54.44	54.19	54.42	54.52	55.02	55.13	55.82	66.87	67.60
2040	62.75	62.70	58.75	55.93	55.68	55.91	56.01	56.52	56.64	57.34	68.60	69.34
2041	64.04	63.98	59.95	57.08	56.83	57.06	57.17	57.68	57.80	58.52	70.00	70.76

					T	ABLE 3a						
						ded Cost						
				Standard	Fixed P	rice Optic	on for So	lar QF				
				0	n-Peak F	orecast (\$/MWH)					
								i				
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	28.21	22.46	15.61	14.71	12.46	16.96	23.96	26.96	24.96	23.71	26.71	31.46
2017	29.96	28.21	24.71	20.96	19.46	20.46	27.96	30.96	29.46	27.71	28.71	33.71
2018	31.71	31.11	28.11	22.13	21.28	21.28	29.93	33.37	30.63	28.61	31.86	35.71
2019	33.94	31.95	27.97	23.70	22.00	23.13	31.67	35.08	33.37	31.38	32.52	38.21
2020	35.74	33.64	29.45	24.95	23.15	24.35	33.34	36.94	35.14	33.04	34.24	40.24
2021	33.98	33.89	31.96	31.24	30.96	31.05	31.16	31.28	31.39	32.03	35.15	35.27
2022	34.92	34.75	33.98	33.04	32.72	32.82	32.94	33.08	33.20	33.74	37.28	37.61
2023	37.09	36.90	35.52	34.32	34.21	34.31	34.44	34.58	34. 7 1	35.26	38.69	38.83
2024	38.86	38.54	37.36	35.98	35.79	35.90	36.04	36.19	36.32	36.88	41.18	41.33
2025	41.08	41.19	39.73	38.77	38.92	39.03	39.19	39.36	39.51	39.69	46.46	46.78
2026	48.37	48.49	45.97	44.48	44.42	44.56	44.75	44.94	45.10	45.56	52.22	51.91
2027	49.34	49.25	47.62	45.61	45.38	45.51	45.48	45.81	45.95	46.45	53.87	53.63
2028	51.08	51.07	49.72	47.22	47.06	47.22	47.07	47.40	47.72	48.41	56.42	55.31
2029	55.08	55.01	52.26	49.77	48.99	49.17	48.73	49.08	49.63	50.36	59.40	59.13
2030	57.87	57.81	55.14	52.89	52.67	52.84	52.88	53.27	53.39	53.95	62.69	62.97
2031	59.07	59.00	56.28	53.98	53.76	53.93	53.98	54.37	54.49	55.06	63.98	64.26
2032	62.83	62.78	59.56	57.16	56.94	57.13	57.21	57.64	57.75	58.34	67.85	68.39
2033	64.49	64.44	61.09	58.64	58.42	58.62	58.70	59.14	59.25	59.86	69.60	70.18
2034	66.10	66.05	62.58	60.08	59.85	60.05	60.14	60.59	60.70	61.32	71.31	71.94
2035	67.84	67.79	64.20	61.64	61.41	61.62	61.71	62.17	62.28	62.92	73.16	73.83
2036	69.43	69.38	65.72	63.11	62.88	63.09	63.19	63.66	63.77	64.42	74.85	75.54
2037	71.08	71.04	67.30	64.64	64.40	64.62	64.72	65.20	65.31	65.97	76.61	77.31
2038	72.78	72.73	68.93	66.22	65.98	66.20	66.30	66.78	66.90	67.57	78.42	79.13
2039	74.28	74.23	70.35	67.58	67.34	67.56	67.67	68.16	68.28	68.97	80.02	80.75
2040	76.15	76.10	72.15	69.33	69.08	69.31	69.42	69.92	70.04	70.74	82.01	82.75
2041	77.69	77.64	73.61	70.74	70.48	70.72	70.82	71.34	71.46	72.17	83.66	84.41

			-,		T/	BLE 3b						
					Avoi	ded Cost	s					
				Standard				lar QF				
				Of	f-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	25.61	20.71	13.96	11.41	6.31	10.11	15.71	20.96	20.96	21.21	23.46	26.71
2017	25.71	24.21	22.21	15.71	13.71	12.71	19.71	25.21	25.46	24.71	25.71	27.96
2018	26.17	28.12	25.56	19.46	14.68	12.54	19.71	27.04	26.93	25.35	28.20	30.62
2019	29.84	28.09	25.75	18.15	15.81	14.64	22.83	29.26	29.55	28.67	29.84	32.47
2020	31.75	29.88	27.38	19.28	16.79	15.54	24.27	31.12	31.43	30.50	31.75	34.55
2021	28.88	28.79	26.86	26.15	25.87	25.95	26.07	26.19	26.30	26.94	30.06	30.18
2022	29.73	29.56	28.79	27.85	27.53	27.63	27.75	27.88	28.00	28.54	32.09	32.42
2023	31.78	31.59	30.21	29.01	28.90	29.00	29.14	29.27	29.40	29.95	33.38	33.52
2024	33.48	33.16	31.98	30.60	30.41	30.52	30.66	30.81	30.95	31.51	35.80	35.96
2025	35.58	35.69	34.24	33.27	33.42	33.53	33.70	33.86	34.01	34.19	40.97	41.28
2026	42.77	42.89	40.36	38.87	38.81	38.95	39.15	39.34	39.50	39.95	46.62	46.31
2027	43.63	43.54	41.91	39.89	39.66	39.80	39.77	40.09	40.24	40.74	48.16	47.92
2028	45.26	45.25	43.90	41.40	41.23	41.40	41.25	41.58	41.89	42.59	50.60	49.48
2029	4 9.15	49.08	46.32	43.83	43.06	43.24	42.80	43.15	43.70	44.43	53.46	53.20
2030	51.82	51.76	49.09	46.84	46.62	46.79	46.83	47.22	47.34	47.90	56.64	56.92
2031	52.90	52.84	50.11	47.82	47.59	47.77	47.81	48.21	48.33	48.90	57.81	58.10
2032	56.59	56.54	53.31	50.92	50.70	50.89	50.97	51.39	51.50	52.10	61.60	62.15
2033	58.08	58.03	54.69	52.24	52.02	52.21	52.30	52.73	52.84	53.45	63.19	63.78
2034	59.54	59.50	56.03	53.52	53.30	53.50	53.59	54.04	54.15	54.77	64.76	65.39
2035	61.18	61.14	57.54	54.98	54.75	54.96	55.06	55.52	55.62	56.26	66.50	67.17
2036	62.67	62.62	58.96	56.35	56.12	56.33	56.43	56.89	57.00	57.65	68.09	68.78
2037	64.17	64.12	60.39	57.73	57.49	57.71	57.80	58.28	58.39	59.06	69.69	70.39
2038	65.73	65.69	61.88	59.17	58.93	59.15	59.25	59.73	59.85	60.52	71.37	72.08
2039	67.09	67.04	63.16	60.40	60.15	60.38	60.48	60.98	61.09	61.78	72.83	73.56
2040	68.83	68.78	64.83	62.01	61.76	61.99	62.09	62.60	62.72	63.42	74.68	75.42
2041	70.23	70.17	66.14	63.27	63.02	63.25	63.36	63.87	63.99	64.71	76.19	76.95

PRICING OPTIONS FOR STANDARD PPA (Continued)

2) Renewable Fixed Price Option

The Renewable Fixed Price Option is based on Renewable Avoided Costs. It is available only to Renewable QFs that generate electricity from a renewable energy source that may be used by the Company to comply with the Oregon Renewable Portfolio Standard as set forth in ORS 469A.005 to 469A.210.

This option is available for a maximum term of 15 years. Prices will be as established at the time the Standard PPA is executed and will be equal to the Renewable Avoided Costs in Tables 4a and 4b, 5a and 5b, or 6a and 6b, depending on the type of QF, effective at execution. QFs using any resource type other than wind and solar are assumed to be Base Load QFs.

Sellers will retain all Environmental Attributes generated by the facility during the Renewable Resource Sufficiency Period. A Renewable QF choosing the Renewable Fixed Price Option must cede all RPS Attributes generated by the facility to the Company from the start of the Renewable Resource Deficiency Period through the remainder of the PPA term.

Prices paid to the Seller under the Renewable Fixed Price Option include adjustments for the capacity contribution of the QF resource type relative to that of the avoided proxy resource. Both Wind QF resources (Tables 5a and 5b) and the avoided proxy resource, the basis used to determine Renewable Avoided Costs for the Renewable Fixed Price Option, are assumed to have a capacity contribution to peak of 5%. The capacity contribution for Solar QF resources (Tables 6a and 6b) is assumed to be 5%. The capacity contribution for Base Load QF resources (Tables 4a and 4b) is assumed to be 100%.

The Renewable Avoided Costs during the Renewable Resource Deficiency Period reflect an increase for avoided wind integration costs, shown in Table 7.

Prices paid to the Seller under the Renewable Fixed Price Option for Wind QFs (Tables 5a and 5b) include a reduction for the wind integration costs in Table 7, which cancels out wind integration costs included in the Renewable Avoided Costs during the Renewable Resource Deficiency Period. However, if the Wind QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the wind integration charges in Table 7, in addition to the prices listed in Tables 5a and 5b.

Sellers with PPAs exceeding 15 years will receive pricing equal to the Mid-C Index Price for all years up to five in excess of the initial 15.

	TABLE 4a												
				F	Renewabl	e Avoide	d Costs						
			Rer	newable f	ixed Pric	e Option	for Base	Load Q	F				
				0	n-Peak F	orecast (\$/MWH)						
	-												
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2016	28.36	22.61	15.76	14.86	12.61	17.11	24.11	27.11	25.11	23.86	26.86	31.61	
2017	30.11	28.36	24.86	21.11	19.61	20.61	28.11	31.11	29.61	27.86	28.86	33.86	
2018	31.86	31.26	28.26	22.28	21.43	21.43	30.08	33.52	30.78	28.76	32.01	35.86	
2019	34.10	32.11	28.13	23.86	22.16	23.29	31.83	35.24	33.53	31.54	32.68	38.37	
2020	115.34	115.32	114.56	115.02	118.22	117.33	117.01	116.89	115.60	114.63	115.47	114.45	
2021	117.94	118.18	116.67	117.75	120.59	119.83	119.26	119.77	118.26	117.25	118.55	117.22	
2022	120.48	120.36	118.46	120.19	123.17	122.14	121.69	121.65	120.55	119.55	120.98	119.53	
2023	123.26	122.83	120.85	122.92	125.37	124.64	124.29	123.92	123.08	121.92	123.63	122.53	
2024	124.86	125.01	123.06	125.07	127.80	126.78	126.67	126.41	126.22	123.83	124.83	124.96	
2025	127. 7 3	128.05	125.86	128.21	131.66	130.48	129.53	129.66	128.84	126.59	127.76	127.41	
2026	130.91	130.58	129.12	131.30	135.76	132.28	132.28	132.69	132.40	129.34	131.17	130.23	
2027	133.47	133.03	131.38	133.50	139.48	134.88	134.51	135.95	134.79	131.96	133.26	132.78	
2028	135.95	134.91	132.89	136.24	141.79	136.93	137.64	137.65	136.77	134.76	135.84	135.06	
2029	138.81	138.57	135.91	139.29	149.30	140.74	140.82	140.82	140.86	137.50	138.32	138.21	
2030	141.68	141.39	139.11	142.00	153.18	145.20	143.05	142.93	144.31	140.18	140.75	140.79	
2031	144.29	143.79	142.17	145.52	156.10	149.27	145.71	146.65	146.86	143.04	144.15	143.71	
2032	146.51	146.00	144.35	147.76	158.51	151.58	147.95	148.91	149.13	145.24	146.37	145.92	
2033	149.91	149.40	147.71	151.19	162.18	155.09	151.39	152.37	152.59	148.62	149.77	149.31	
2034	152.96	152.43	150.71	154.26	165.46	158.24	154.46	155.46	155.68	151.64	152.81	152.35	
2035	155.76	155.22	153.46	157.08	168.50	161.14	157.29	158.31	158.54	154.41	155.60	155.13	
2036	158.31	157.76	155.97	159.65	171.26	163.78	159.86	160.90	161.13	156.94	158.15	157.67	
2037	1 61.83	161.27	159.44	163.20	175.07	167.42	163.42	164.48	164.71	160.43	161.67	161.18	
2038	164.95	164.38	162.52	166.35	178.45	170.65	166.57	167.65	167.89	163.52	164.79	164.29	
2039	168.13	167.55	165.66	169.56	181.89	173.94	169.79	170.89	171.13	166.68	167.97	167.46	
2040	171.05	170.46	168.54	172.51	185.04	176.96	172.74	173.85	174.10	169.58	170.89	170.37	
2041	174.69	174.08	172.11	176.17	188.98	180.72	176.40	177.55	177.80	173.18	174.52	173.99	

					TA	ABLE 4b						
				R	enewable	e Avoided	Costs					
			Ren	ewable F	ixed Pric	e Option	for Base	Load Qi	:			
				0	ff-Peak F	orecast (\$/MWH)					-
	:			:								
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	25.76	20.86	14.11	11.56	6.46	10.26	15.86	21.11	21.11	21.36	23.61	26.86
2017	25.86	24.36	22.36	15.86	13.86	12.86	19.86	25.36	25.61	24.86	25.86	28.11
2018	26.32	28.27	25,71	19.61	14.83	12.69	19.86	27.19	27.08	25.50	28.35	30.77
2019	30.00	28.25	25.91	18.31	15.97	14.80	22.99	29.42	29.71	28.83	30.00	32.63
2020	62.76	63.02	64.56	63.31	59.92	60.16	60.45	61.61	62.52	63.74	63.55	63.99
2021	64.93	64.15	65.85	64.48	61.58	61.62	62.27	62.62	63.78	65.82	63.38	65.09
2022	65.85	65.52	67.77	65.49	62.45	62.82	64.33	63.35	65.00	67.04	64.42	66.29
2023	66.70	66.75	69.10	67.28	62.84	64.01	65.40	64.85	66.14	68.41	65.38	67.63
2024	67.25	67.31	70.47	67.09	63.18	65.92	64.75	65.12	66.62	68.68	67.42	68.05
2025	68.62	68.60	71.94	68.08	63.17	66.28	66.12	67.12	67.23	70.19	69.68	69.06
2026	68.95	69.85	72.28	68.56	63.85	67.22	67.05	67.75	67.05	71.12	69.85	69.89
2027	71.31	71.29	73.13	70.34	63.69	68.45	68.79	68.16	68.57	73.22	70.67	71.18
2028	72.28	72.90	75.41	72.10	63.09	69.98	70.15	68.82	70.20	73.79	71.48	73.41
2029	72.78	73.60	76.79	73.50	58.25	70.29	71.37	70.00	71.53	74.58	73.61	74.68
2030	73.91	74.82	78.36	73.64	58.00	70.89	72.02	72.19	72.00	75.99	75.36	76.23
2031	75.51	76.70	79.40	74.00	59.17	70.67	73.55	73.71	72.16	77.24	77.07	76.31
2032	76.76	77.97	80.71	75.23	60.15	71.83	74.76	74.93	73.35	78.52	78.34	77.57
2033	78.46	79.69	82.50	76.89	61.48	73.42	76.42	76.58	74.97	80.25	80.07	79.29
2034	79.97	81.23	84.09	78.37	62.66	74.84	77.89	78.06	76.42	81.80	81.62	80.82
2035	81.52	82.80	85.71	79.88	63.87	76.28	79.39	79.57	77.89	83.38	83.19	82.38
2036	82.86	84.17	87.13	81.20	64.93	77.54	80.70	80.88	79.18	84.76	84.57	83.74
2037	84.69	86.03	89.05	83.00	66.36	79.25	82.49	82.67	80.93	86.63	86.44	85.59
2038	86.33	87.69	90.77	84.60	67.64	80.78	84.08	84.26	82.49	88.30	88.11	87.24
2039	87.99	89.38	92.52	86.23	68.95	82.34	85.70	85.89	84.08	90.01	89.81	88.92
2040	89.45	90.85	94.05	87.66	70.09	83.70	87.12	87.31	85.47	91.49	91.29	90.39
2041	91.42	92.86	96.13	89,59	71.63	85.55	89.04	89.24	87.36	93.51	93.31	92.39

	TABLE 5a											
	Renewable Avoided Costs											
	Renewable Fixed Price Option for Wind QF											
	On-Peak Forecast (\$/MWH)											
	<u>-</u>	= .	3.4	A	Blove	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Year	Jan 24.52	Feb 18.77	Mar 11.92	Apr 11.02	May 8.77	13.27	20.27	23.27	21.27	20.02	23.02	27.77
2016	26.20	24.45	20.95	17.20	15.70	16.70	24.20	27.20	25.70	23.95	24.95	29.95
2017	27.87	27.27	24.27	18.29	17.44	17.44	26.09	29.53	26.79	24.77	28.02	31.87
2018 2019	30.03	28.04	24.27	19.79	18.09	19.22	27.76	31.17	29.46	27.47	28.61	34.30
2019	75.38	75.37	74.61	75.06	78.26	77.37	77.05	76.93	75.64	74.67	75.51	74.49
2020	77.10	77.33	75.83	76.90	79.75	78.99	78.41	78.92	77.41	76.40	77.70	76.38
2021	78.85	78.72	76.82	78.56	81.53	80.51	80,05	80.02	78.92	77.92	79.34	77.90
2023	80.71	80.27	78.29	80.37	82.82	82.08	81.73	81.37	80.53	79.36	81.08	79.97
2024	81.74	81.89	79.93	81.95	84.68	83.66	83.55	83.28	83.10	80.71	81.71	81.84
2025	83.64	83.97	81.78	84.13	87.57	86.40	85.44	85.57	84.75	82.51	83.68	83.32
2026	85.97	85.64	84.18	86.37	90.82	87.34	87.34	87.75	87.46	84.40	86.23	85.29
2027	87.67	87.23	85.57	87.69	93.67	89.07	88.71	90.15	88.99	86.16	87.45	86.98
2028	89.26	88.22	86.20	89.55	95.10	90.24	90.95	90.96	90.08	88.07	89.15	88.37
2029	91.22	90.98	88.32	91.70	101.72	93.16	93.23	93.23	93.28	89.92	90.73	90.62
2030	93.17	92.88	90.60	93.49	104.67	96.69	94.54	94.42	95.80	91.67	92.24	92.28
2031	94.84	94.34	92.72	96.07	106.65	99.82	96.26	97.20	97.42	93.59	94.70	94.26
2032	96.40	95.90	94.24	97.65	108.40	101.47	97.85	98.80	99.02	95.13	96.26	95.82
2033	98.55	98.03	96.34	99.82	110.81	103.72	100.02	101.00	101.22	97.25	98.40	97.95
2034	100.44	99.91	98.19	101.74	112.94	105.72	101.94	102.94	103.17	99.12	100.29	99.83
2035	102.38	101.85	100.09	103.71	115.13	107.76	103.92	104.93	105.16	101.04	102.23	101.76
2036	104.06	103.51	101.72	105.40	117.01	109.53	105.61	106.65	106.88	102.69	103.90	103.42
2037	106.37	105.81	103.99	107.74	119.61	111.96	107.96	109.02	109.26	104.97	106.21	105.72
2038	108.42	107.86	105.99	109.82	121.92	114.12	110.05	111.12	111.37	107.00	108.26	107.76
2039	110.52	109.9 4	108.04	111.95	124.27	116.33	112.17	113.27	113.52	109.07	110.36	109.85
2040	112.32	111.73	109.81	113.77	126.31	118.23	114.00	115.12	115.37	110.85	112.16	111.64
2041	114.83	114.23	112.26	116.31	129.12	120.86	116.55	117.69	117.95	113.32	114.66	114.13

					T/	ABLE 5b						
	Renewable Avoided Costs Renewable Fixed Price Option for Wind QF											
	Off-Peak Forecast (\$/MWH)											
						1	11	Aum	Con	Oct	Nov	Dec
Year	Jan	Feb	Mar	Apr	May	Jun	Jul 12.02	Aug 17.27	Sep 17.27	17.52	19.77	23.02
2016	21.92	17.02	10.27	7.72	2.62	6.42	15.95	21.45	21.70	20.95	21.95	24.20
2017	21.95	20.45	18.45	11.95	9.95	8.95		23.20	23.09	21.51	24.36	26.78
2018	22.33	24.28	21.72	15.62	10.84	8.70	15.87		25.64		25.93	28.56
2019	25.93	24.18	21.84	14.24	11.90	10.73	18.92	25.35		24.76		
2020	58.61	58.87	60.41	59.16	55.77	56.01	56.30	57.46	58.37	59.59	59.40	59.84 60.86
2021	60.70	59.92	61.62	60.25	57.35	57.39	58.04	58.39	59.55	61.59	59.15	
2022	61.54	61.21	63.46	61.18	58.14	58.51	60.02	59.04	60.69	62.73	60.11	61.98
2023	62.31	62.36	64.71	62.89	58.45	59.62	61.01	60.46	61.75	64.02	60.99	63.24
2024	62.78	62.84	66.00	62.62	58.71	61.45	60.28	60.65	62.15	64.21	62.95	63.58
2025	64.06	64.04	67.38	63.52	58.61	61.72	61.56	62.56	62.67	65.63	65.12	64.50
2026	64.30	65.20	67.63	63.91	59.20	62.57	62.40	63.10	62.40	66.47	65.20	65.24
2027	66.57	66.55	68.39	65.60	58.95	63.71	64.05	63.42	63.83	68.48	65.93	66.44
2028	67.45	68.07	70.58	67.27	58.26	65.15	65.32	63.99	65.37	68.96	66.65	68.58
2029	67.86	68.68	71.87	68.58	53.33	65.37	66.45	65.08	66.61	69.66	68.69	69.76
2030	68.89	69.80	73.34	68.62	52.98	65.87	67.00	67.17	66.98	70.97	70.34	71.21
2031	70.39	71.58	74.28	68.88	54.05	65.55	68.43	68.59	67.04	72.12	71.95	71.19
2032	71.55	72.76	75.50	70.02	54.94	66.62	69.55	69.72	68.14	73.31	73.13	72.36
2033	73.15	74.38	77.19	71.58	56.17	68.11	71.11	71.27	69.66	74.94	74.76	73.98
2034	74.55	75.81	78.67	72.95	57.24	69.42	72.47	72.64	71.00	76.38	76.20	75.40
2035	76.00	77.28	80.19	74.36	58.35	70.76	73.87	74.05	72.37	77.86	77.67	76.86
2036	77.23	78.54	81.50	75.57	59.30	71.91	75.07	75.25	73.55	79.13	78.94	78.11
2037	78.95	80.29	83.31	77.26	60.62	73.51	76.75	76.93	75.19	80.89	80.70	79.85
2038	80.48	81.84	84.92	78. 7 5	61.79	74.93	78.23	78.41	76.64	82.45	82.26	81.39
2039	82.03	83.42	86.56	80.27	62.99	76.38	79.74	79.93	78.12	84.05	83.85	82.96
2040	83.37	84.77	87.97	81.58	64.01	77.62	81.04	81.23	79.39	85.41	85.21	84.31
2041	85.23	86.67	89.94	83.40	65.44	79.36	82.85	83.05	81.17	87.32	87.12	86.20

					TA	ABLE 6a						
	Renewable Avoided Costs											
	Renewable Fixed Price Option for Solar QF											
	On-Peak Forecast (\$/MWH)											
			· · · · · · · · · · · · · · · · · · ·						0	0-4	Nave	D.,
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep 25.11	Oct 23.86	Nov 26.86	Dec 31.61
2016	28.36	22.61	15.76	14.86	12.61	17.11	24.11	27.11			28.86	33.86
2017	30.11	28.36	24.86	21.11	19.61	20.61	28.11	31.11	29.61	27.86	32.01	35.86
2018	31.86	31.26	28.26	22.28	21.43	21.43	30.08	33.52	30.78	28.76		38.37
2019	34.10	32.11	28.13	23.86	22.16	23.29	31.83	35.24	33.53	31.54	32.68	
2020	78.62	78.60	77.84	78.30	81.50	80.60	80.29	80.17	78.88	77.91	78.74	77.73
2021	80.39	80.63	79.12	80.20	83.04	82.28	81.71	82.22	80.71	79.70	81.00	79.67
2022	82.21	82.08	80.18	81.92	84.89	83.87	83.41	83.38	82.27	81.27	82.70	81.25
2023	84.12	83.69	81.71	83.78	86.23	85.50	85.15	84.78	83.94	82.78	84.50	83.39
2024	85.22	85.37	83.41	85.43	88.16	87.14	87.03	86.76	86.58	84.19	85.19	85.32
2025	87.19	87.52	85.33	87.68	91.12	89.95	88.99	89.12	88.30	86.06	87.23	86.87
2026	89.59	89.26	87.80	89.99	94.44	90.96	90.96	91.37	91.08	88.02	89.85	88.91
2027	91.36	90.92	89.26	91.39	97.36	92.76	92.40	93.84	92.68	89.85	91.14	90.67
2028	93.02	91.98	89.96	93.31	98.86	94.00	94.71	94.72	93.84	91.84	92.91	92.13
2029	95.05	94.81	92.15	95.53	105.55	96.99	97.06	97.06	97.11	93.75	94.56	94.45
2030	97.08	96.79	94.51	97.40	108.58	100.60	98.45	98.33	99.71	95.58	96.15	96.19
2031	98.83	98.33	96.70	100.05	110.63	103.81	100.25	101.19	101.40	97.58	98.69	98.25
2032	100.47	99.96	98.30	101.71	112.47	105.53	101.91	102.87	103.08	99.20	100.32	99.88
2033	102.68	102.16	100.47	103.95	114.95	107.86	104.16	105.14	105.36	101.38	102.53	102.08
2034	104.66	104.13	102.41	105.96	117.16	109.94	106.16	107.16	107.38	103.34	104.51	104.05
2035	106.68	106.15	104.39	108.01	119.43	112.06	108.21	109.23	109.46	105.34	106.53	106.06
2036	108.44	107.90	106.11	109.79	121.40	113.91	110.00	111.04	111.27	107.08	108.29	107.81
2037	110.84	110.28	108.46	112.21	124.08	116.43	112.43	113.49	113.73	109.44	110.68	110.19
2038	112.98	112.41	110.55	114.38	126.47	118.68	114.60	115.68	115.92	111.55	112.82	112.32
2039	115.16	114.58	112.68	116.59	128.92	120.97	116.81	117.91	118.16	113.71	115.00	114.49
2040	117.06	116.47	114.54	118.51	131.04	122.96	118.74	119.86	120.11	115.58	116.89	116.37
2041	119.65	119.05	117.07	121.13	133.94	125.68	121.37	122.51	122.76	118.14	119.48	118.95

		AME .			TA	BLE 6b		June -			1	
	Renewable Avoided Costs											
	Renewable Fixed Price Option for Solar QF Off-Peak Forecast (\$/MWH)											

Year	Jan	Feb	Mar	Apr	May	Jun	Jui	Aug	Sep	Oct	Nov	Dec
2016	25.76	20.86	14.11	11.56	6.46	10.26	15.86	21.11	21.11	21.36	23.61	26.86
2017	25.86	24.36	22.36	15.86	13.86	12.86	19.86	25.36	25.61	24.86	25.86	28.11
2018	26.32	28.27	25.71	19.61	14.83	12.69	19.86	27.19	27.08	25.50	28.35	30.77
2019	30.00	28.25	25.91	18.31	15.97	14.80	22.99	29.42	29.71	28.83	30.00	32.63
2020	62.76	63.02	64.56	63.31	59.92	60.16	60.45	61.61	62.52	63.74	63.55	63.99
2021	64.93	64.15	65.85	64.48	61.58	61.62	62.27	62.62	63.78	65.82	63.38	65.09
2022	65.85	65.52	67.77	65.49	62.45	62.82	64.33	63.35	65.00	67.04	64.42	66.29
2023	66.70	66.75	69.10	67.28	62.84	64.01	65.40	64.85	66.14	68.41	65.38	67.63
2024	67.25	67.31	70.47	67.09	63.18	65.92	64.75	65.12	66.62	68.68	67.42	68.05
2025	68.62	68.60	71.94	68.08	63.17	66.28	66.12	67.12	67.23	70.19	69.68	69.06
2026	68.95	69.85	72.28	68.56	63.85	67.22	67.05	67.75	67.05	71.12	69.85	69.89
2027	71.31	71.29	73.13	70.34	63.69	68.45	68.79	68.16	68.57	73.22	70.67	71.18
2028	72.28	72.90	75.41	72.10	63.09	69.98	70.15	68.82	70.20	73.79	71.48	73.41
2029	72.78	73.60	76.79	73.50	58.25	70.29	71.37	70.00	71.53	74.58	73.61	74.68
2030	73.91	74.82	78.36	73.64	58.00	70.89	72.02	72.19	72.00	75.99	75.36	76.23
2031	75.51	76.70	79.40	74.00	59.17	70.67	73.55	73.71	72.16	77.24	77.07	76.31
2032	76.76	77.97	80.71	75.23	60.15	71.83	74.76	74.93	73.35	78.52	78.34	77.57
2033	78.46	79.69	82.50	76.89	61.48	73.42	76.42	76.58	74.97	80.25	80.07	79.29
2034	79.97	81.23	84.09	78.37	62.66	74.84	77.89	78.06	76.42	81.80	81.62	80.82
2035	81.52	82.80	85.71	79.88	63.87	76.28	79.39	79.57	77.89	83.38	83.19	82.38
2036	82.86	84.17	87.13	81.20	64.93	77.54	80.70	80.88	79.18	84.76	84.57	83.74
2037	84.69	86.03	89.05	83.00	66.36	79.25	82.49	82.67	80.93	86.63	86.44	85.59
2038	86.33	87.69	90.77	84.60	67.64	80.78	84.08	84.26	82.49	88.30	88.11	87.24
2039	87.99	89.38	92.52	86.23	68.95	82.34	85.70	85.89	84.08	90.01	89.81	88.92
2040	89.45	90.85	94.05	87.66	70.09	83.70	87.12	87.31	85.47	91.49	91.29	90.39
2041	91.42	92.86	96.13	89.59	71.63	85.55	89.04	89.24	87.36	93.51	93.31	92.39

WIND INTEGRATION

TABLE 7								
Wind Integration								
Year	Cost							
2015	3.77							
2016	3.84							
2017	3.91							
2018	3.99							
2019	4.07							
2020	4.15							
2021	4.23							
2022	4.31							
2023	4.39							
2024	4.47							
2025	4.56							
2026	4.65							
2027	4.74							
2028	4.83							
2029	4.92							
2030	5.02							
2031	5.12							
2032	5.21							
2033	5.31							
2034	5.42							
2035	5.52							
2036	5.63							
2037	5.74							
2038	5.85							
2039	5.96							
2040	6.08							

MONTHLY SERVICE CHARGE

Each separately metered QF not associated with a retail Customer account will be charged \$10.00 per month.

INSURANCE REQUIREMENTS

The following insurance requirements are applicable to Sellers with a Standard PPA:

- 1) QFs with nameplate capacity ratings greater than 200 kW are required to secure and maintain a prudent amount of general liability insurance. The Seller must certify to the Company that it is maintaining general liability insurance coverage for each QF at prudent amounts. A prudent amount will be deemed to mean liability insurance coverage for both bodily injury and property damage liability in the amount of not less than \$1,000,000 each occurrence combined single limit, which limits may be required to be increased or decreased by the Company as the Company determines in its reasonable judgment, that economic conditions or claims experience may warrant.
- Such insurance will include an endorsement naming the Company as an additional insured insofar as liability arising out of operations under this schedule and a provision that such liability policies will not be canceled or their limits reduced without 30 days' written notice to the Company. The Seller will furnish the Company with certificates of insurance together with the endorsements required herein. The Company will have the right to inspect the original policies of such insurance.
- 3) QFs with a design capacity of 200 kW or less are encouraged to pursue liability insurance on their own. The Oregon Public Utility Commission in Order No. 05-584 determined that it is inappropriate to require QFs that have a design capacity of 200 kW or less to obtain general liability insurance.

TRANSMISSION AGREEMENTS

If the QF is located outside the Company's service territory, the Seller is responsible for the transmission of power at its cost to the Company's service territory.

INTERCONNECTION REQUIREMENTS

Except as otherwise provided in a generation Interconnection Agreement between the Company and Seller, if the QF is located within the Company's service territory, switching equipment capable of isolating the QF from the Company's system will be accessible to the Company at all times. At the Company's option, the Company may operate the switching equipment described above if, in the sole opinion of the Company, continued operation of the QF in connection with the utility's system may create or contribute to a system emergency.

INTERCONNECTION REQUIREMENTS (Continued)

The QF owner interconnecting with the Company's distribution system must comply with all requirements for interconnection as established pursuant to Commission rule, in the Company's Rules and Regulations (Rule C) or the Company's Interconnection Procedures contained in its FERC Open Access Transmission Tariff (OATT), as applicable. The Seller will bear full responsibility for the installation and safe operation of the interconnection facilities.

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE PRICING UNDER THE STANDARD PPA

A QF will be eligible to receive pricing under the Standard PPA if the nameplate capacity of the QF, together with any other electric generating facility using the same motive force, owned or controlled by the Same Person(s) or Affiliated Person(s), and located at the Same Site, does not exceed 10 MW. A Community-Based or Family-Owned QF is exempt from these restrictions.

Definition of Community-Based

- a. A community project (or a community sponsored project) must have a recognized and established organization located within the county of the project or within 50 miles of the project that has a genuine role in helping the project be developed and must have some not insignificant continuing role with or interest in the project after it is completed and placed in service.
- b. After excluding the passive investor whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit, the equity (ownership) interests in a community sponsored project must be owned in substantial percentage (80 percent or more) by the following persons (individuals and entities): (i) the sponsoring organization, or its controlled affiliates; (ii) members of the sponsoring organization (if it is a membership organization) or owners of the sponsorship organization (if it is privately owned); (iii) persons who live in the county in which the project is located; or (iv) units of local government, charities, or other established nonprofit organizations active either in the county in which the project is located or active in a county adjoining the county in which the project is located.

Definition of Family-Owned

After excluding the ownership interest of the passive investor whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit, five or fewer individuals own 50 percent or more of the equity of the project entity, or fifteen or fewer individuals own 90 percent or more of the project entity. A "look through" rule applies to closely held entities that hold the project entity, so that equity held by LLCs, trusts, estates, corporations, partnerships or other similar entities is considered held by the equity owners of the look through entity. An individual is a natural person. In counting to five or fifteen, spouses or children of an equity owner of the project owner who also have an equity interest are aggregated and counted as a single individual.

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE PRICING UNDER THE STANDARD PPA (Continued)

Definition of Person(s) or Affiliated Person(s)

As used above, the term "Same Person(s)" or "Affiliated Person(s)" means a natural person or persons or any legal entity or entities sharing common ownership, management or acting jointly or in concert with or exercising influence over the policies or actions of another person or entity. However, two facilities will not be held to be owned or controlled by the Same Person(s) or Affiliated Person(s) solely because they are developed by a single entity.

Furthermore, two facilities will not be held to be owned or controlled by the Same Person(s) or Affiliated Person(s) if such common person or persons is a "passive investor" whose ownership interest in the QF is primarily related to utilizing production tax credits, green tag values and MACRS depreciation as the primary ownership benefit and the facilities at issue are independent family-owned or community-based projects. A unit of Oregon local government may also be a "passive investor" in a community-based project if the local governmental unit demonstrates that it will not have an equity ownership interest in or exercise any control over the management of the QF and that its only interest is a share of the cash flow from the QF, which share will not exceed 20%. The 20% cash flow share limit may only be exceeded for good cause shown and only with the prior approval of the Commission.

Definition of Same Site

For purposes of the foregoing, generating facilities are considered to be located at the same site as the QF for which qualification for pricing under the Standard PPA is sought if they are located within a five-mile radius of any generating facilities or equipment providing fuel or motive force associated with the QF for which qualification for pricing under the Standard PPA is sought.

Definition of Shared Interconnection and Infrastructure

QFs otherwise meeting the above-described separate ownership test and thereby qualified for entitlement to pricing under the Standard PPA will not be disqualified by utilizing an interconnection or other infrastructure not providing motive force or fuel that is shared with other QFs qualifying for pricing under the Standard PPA so long as the use of the shared interconnection complies with the interconnecting utility's safety and reliability standards, interconnection agreement requirements and Prudent Electrical Practices as that term is defined in the interconnecting utility's approved Standard PPA.

OTHER DEFINITIONS

Mid-C Index Price

As used in this schedule, the daily Mid-C Index Price shall be the Day Ahead Intercontinental Exchange ("ICE") for the bilateral OTC market for energy at the Mid-C Physical for Average

OTHER DEFINITIONS (Continued)

On-Peak Power and Average Off-Peak Power found on the following website: https://www.theice.com/products/OTC/Physical-Energy/Electricity. In the event ICE no longer publishes this index, PGE and the Seller agree to select an alternative successor index representative of the Mid-C trading hub.

Definition of RPS Attributes

As used in this schedule, RPS Attributes means all attributes related to the Net Output generated by the Facility that are required in order to provide PGE with "qualifying electricity," as that term is defined in Oregon's Renewable Portfolio Standard Act, Ore. Rev. Stat. 469A.010, in effect at the time of execution of this Agreement. RPS Attributes do not include Environmental Attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity and not needed to ensure that there are zero net emissions associated with the generation of electricity.

Definition of Environmental Attributes

As used in this schedule, Environmental Attributes shall mean any and all claims, credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical, or other substance to the air, soil or water. Environmental Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil, or water such as (subject to the foregoing) sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; and (2) any avoided emissions of carbon dioxide (CO2), methane (CH4), and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere.

Definition of Resource Sufficiency Period

This is the period from the current year through 2020.

Definition of Resource Deficiency Period

This is the period from 2021 through 2034.

Definition of Renewable Resource Sufficiency Period

This is the period from the current year through 2019.

Definition of Renewable Resource Deficiency Period

This is the period from 2020 through 2034.

SCHEDULE 201 (Concluded)

DISPUTE RESOLUTION

Upon request, the QF will provide the purchasing utility with documentation verifying the ownership, management and financial structure of the QF in reasonably sufficient detail to allow the utility to make an initial determination of whether or not the QF meets the above-described criteria for entitlement to pricing under the Standard PPA.

The QF may present disputes to the Commission for resolution using the following process:

The QF may file a complaint asking the Commission to adjudicate disputes regarding the formation of the standard contract. The QF may not file such a complaint during any 15-day period in which the utility has the obligation to respond, but must wait until the 15-day period has passed.

The utility may respond to the complaint within ten days of service.

The Commission will limit its review to the issues identified in the complaint and response, and utilize a process similar to the arbitration process adopted to facilitate the execution of interconnection agreements among telecommunications carriers. See OAR 860, Division 016. The administrative law judge will not act as an arbitrator.

SPECIAL CONDITIONS

- 1. Delivery of energy by Seller will be at a voltage, phase, frequency, and power factor as specified by the Company.
- 2. If the Seller also receives retail Electricity Service from the Company at the same location, any payments under this schedule will be credited to the Seller's retail Electricity Service bill. At the option of the Customer, any net credit over \$10.00 will be paid by check to the Customer.
- 3. Unless required by state or federal law, if the 1978 Public Utility Regulatory Policies Act (PURPA) is repealed, PPAs entered into pursuant to this schedule will not terminate prior to the Standard or Negotiated PPA's termination date.

TERM OF AGREEMENT

Not less than one year and not to exceed 20 years.

Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

STANDARD RENEWABLE OFF-SYSTEM VARIABLE POWER PURCHASE

AGREEMENT

THIS AGREEMENT is between <u>Blue Marmot VII LLC</u> ("Seller") and Portland General Electric Company ("PGE") (hereinafter each a "Party" or collectively, "Parties") and is effective upon execution by both Parties ("Effective Date").

RECITALS

Seller intends to construct, own, operate and maintain a <u>Solar</u> facility for the generation of electric power located in <u>Lake (W -120.333, N 42.117)</u> County, <u>Oregon</u> with a Nameplate Capacity Rating of <u>10,000</u> kilowatt ("kW"), as further described in Exhibit A ("Facility"); and

Seller intends to operate the Facility as a "Qualifying Facility," as such term is defined in Section 3.1.3, below.

Seller shall sell and PGE shall purchase the entire Net Output, as such term is defined in Section 1.21, below, from the Facility in accordance with the terms and conditions of this Agreement.

AGREEMENT

NOW, THEREFORE, the Parties mutually agree as follows:

SECTION 1: DEFINITIONS

When used in this Agreement, the following terms shall have the following meanings:

- 1.1. "As-built Supplement" means the supplement to Exhibit A provided by Seller in accordance with Section 4.3 following completion of construction of the Facility, describing the Facility as actually built.
- 1.2. "Base Hours" is defined as the total number of hours in each Contract Year (8,760 or 8,784 for leap year)
- 1.3. "Billing Period" means from the start of the first day of each calendar month to the end of the last day of each calendar month.
- 1.4. "Cash Escrow" means an agreement by two parties to place money into the custody of a third party for delivery to a grantee only after the fulfillment of the conditions specified.
- 1.5. "Commercial Operation Date" means the date that the Facility is deemed by PGE to be fully operational and reliable. PGE may, at its discretion require, among other things, that all of the following events have occurred:
- 1.5.1. (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from a Licensed

Schedule 201

Standard Renewable Off-System Variable Power Purchase Agreement

Professional Engineer ("LPE") acceptable to PGE in its reasonable judgment stating that the Facility is able to generate electric power reliably in accordance with the terms and conditions of this Agreement (certifications required under this Section 1.5 can be provided by one or more LPEs);

- Start-Up Testing of the Facility has been completed in accordance with 1.5.2.
- (facilities with nameplate under 500 kW exempt from following requirement) After PGE has received notice of completion of Start-Up Testing, PGE has Section 1.36; received a certificate addressed to PGE from an LPE stating that the Facility has operated for testing purposes under this Agreement and was continuously mechanically available for operation for a minimum of 120 hours. The Facility must provide ten (10) working days written notice to PGE prior to the start of the initial testing period. If the mechanical availability of the Facility is interrupted during this initial testing period or any subsequent testing period, the Facility shall promptly start a new Test Period and provide PGE forty-eight (48) hours written notice prior to the start of such testing period;
 - (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from an LPE stating that all required interconnection facilities have been constructed and all required interconnection tests have been completed;
 - (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from an LPE stating that Seller has obtained all Required Facility Documents and, if requested by PGE in writing, has provided copies of any or all such requested Required Facility Documents;
 - PGE has received a copy of the executed Generation Interconnection
 - "Contract Price" means the applicable price, including on-peak and offand Transmission Agreements. peak prices, as specified in the Schedule.
 - "Contract Year" means each twelve (12) month period commencing upon the Commercial Operation Date or its anniversary during the Term, except the final Contract Year will be the period from the last anniversary of the Commercial Operation Date during the Term until the end of the Term.
 - "Effective Date" has the meaning set forth in Section 2.1.
 - "Environmental Attributes" shall mean any and all claims, credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical or other substance to the air, soil or Environmental Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil or water such as (subject to the foregoing) sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; and (2) any avoided emissions of carbon dioxide (CO2), methane (CH4), and other greenhouse gasses (GHGs) that have been determined by the United Nations

Schedule 201

Standard Renewable Off-System Variable Power Purchase Agreement

Intergovernmental Panel on Climate Change to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere.

- 1.10. "Facility" has the meaning set forth in the Recitals.
- 1.11. "Generation Interconnection Agreement" means an agreement governing the interconnection of the Facility with Pacificorp electric system.
- 1.12. "Generation Unit" means each separate electrical generator that contributes toward Nameplate Capacity Rating included in Exhibit A. For solar facilities, a generating unit is a complete solar electrical generation system within the Facility that is able to generate and deliver energy to the Point of Delivery independent of other Generation Units within the same Facility.
- 1.13. "Letter of Credit" means an engagement by a bank or other person made at the request of a customer that the issuer will honor drafts or other demands for payment upon compliance with the conditions specified in the letter of credit.
- 1.14. "Licensed Professional Engineer" or "LPE" means a person who is licensed to practice engineering in the state where the Facility is located, who has no economic relationship, association, or nexus with the Seller, and who is not a representative of a consulting engineer, contractor, designer or other individual involved in the development of the Facility, or of a manufacturer or supplier of any equipment installed in the Facility. Such Licensed Professional Engineer shall be licensed in an appropriate engineering discipline for the required certification being made and be acceptable to PGE in its reasonable judgment.
 - 1.15. "Lost Energy" means "Lost Energy" means ((the Guarantee of Mechanical Availability as set forth in 3.1.10 / MAP) X Net Output for a Calendar Year) – Net Output for the Calendar Year. Lost Energy shall be zero unless the result of the calculation in this subsection results in a positive number.
 - "Lost Energy Value" means Lost Energy X the excess of the annual timeweighted average Mid-C Index Price for On Peak Hours and Off Peak Hours over the time weighted average Contract Price for On Peak and Off Peak Hours for the corresponding time period (provided that such excess shall not exceed the Contract Price and further provided that Lost Energy is deemed to be zero prior to reaching the Commercial Operation Date) plus any reasonable costs incurred by PGE to purchase replacement power and/or transmission to deliver the replacement power to the Point of Delivery (For Start-Up Lost Energy Value See 1.35). shall mean that
 - 1.17. "Mechanical Availability Percentage" or "MAP" percentage for any Contract Year for the Facility calculated in accordance with the following formula:

MAP = 100 X (Operational Hours) /(Base Hours X Number of Units)

1.18. "Mid-C Index Price" means the Day Ahead Intercontinental Exchange ("ICE") index price for the bilateral OTC market for energy at the Mid-C Physical for Average On Peak Power and Average Off Peak Power found on the following website:

Schedule 201

Standard Renewable Off-System Variable Power Purchase Agreement

https://www.theice.com/products/OTC/Physical-Energy/Electricity. In the event ICE no longer publishes this index, PGE and the Seller agree to select an alternative successor index representative of the Mid-C trading hub.

- 1.19. "Nameplate Capacity Rating" means the maximum capacity of the Facility as stated by the manufacturer, expressed in kW, which shall not exceed 10,000 kW.
- 1.20. "Net Dependable Capacity" means the maximum capacity the Facility can sustain over a specified period modified for seasonal limitations, if any, and reduced by the capacity required for station service or auxiliaries.
- 1.21. "Net Output" means all energy expressed in kWhs produced by the Facility, less station and other onsite use and less transformation and transmission
- 1.22. "Number of Units" means the number of Generation Units in the Facility as losses. specified in Exhibit A.
 - 1.23. "Off-Peak Hours" has the meaning provided in the Schedule.
 - 1.24. "On-Peak Hours" has the meaning provided in the Schedule.
- 1.25. "Operational Hours" for the Facility means the total across all Generation Units of the number of hours each of the Facility's Generation Units are potentially capable of producing power at its Nameplate Capacity Rating regardless of actual weather conditions, season and the time of day or night, without any mechanical operating constraint or restriction, and potentially capable of delivering such power to the Point of Delivery in a Contract Year. During up to, but not more than, two hundred (200) hours of Planned Maintenance during a Contract Year for each Generation Unit and hours during which an event of Force Majeure exists, a Generation Unit shall be considered potentially capable of delivering such power to the Point of Delivery. For example, in the absence of any Planned Maintenance beyond 200 hours on any Generation Unit or Event of Force Majeure, the Operational Hours for a wind farm with five (5) separate two (2) MW turbines would be 43,800 for a Contract Year.
 - 1.26. "Planned Maintenance" means outages scheduled ninety (90) days in advance, with PGE's prior written consent, which shall not be unreasonably withheld.
 - 1.27. "Point of Delivery" means the PGE system.
 - 1.28. "Pre-Commercial Operation Date Minimum Net Output" shall mean, unless such MWh is specifically set forth by Seller in Exhibit A, an amount in MWh equal to seventy-five percent (75%) of Nameplate Capacity Rating X thirty percent (30%) for a wind or other renewable QF or fifty percent (50%) for a solar QF X (whole months since the date selected in Section 2.2.1 / 12) X (8760 hours – 200 hours (assumed Planned Maintenance)) for each month. If Seller has provided specific expected monthly Net Output amounts for the Facility in Exhibit A, "Pre-Commercial Operation Date Minimum Net Output" shall mean seventy-five percent (75%) X expected net output set forth in Exhibit A for each month.

- 1.29. "Prime Rate" means the publicly announced prime rate or reference rate for commercial loans to large businesses with the highest credit rating in the United States in effect from time to time quoted by Citibank, N.A. If a Citibank, N.A. prime rate is not available, the applicable Prime Rate shall be the announced prime rate or reference rate for commercial loans in effect from time to time quoted by a bank with \$10 billion or more in assets in New York City, N.Y., selected by the Party to whom interest based on the prime rate is being paid.
 - 1.30. "Prudent Electrical Practices" means those practices, methods, standards and acts engaged in or approved by a significant portion of the electric power industry in the Western Electricity Coordinating Council that at the relevant time period, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with good business practices, reliability, economy, safety and expedition, and which practices, methods, standards and acts reflect due regard for operation and maintenance standards recommended by applicable equipment suppliers and manufacturers, operational limits, and all applicable laws and regulations. Prudent Electrical Practices are not intended to be limited to the optimum practice, method, standard or act to the exclusion of all others, but rather to those practices, methods and acts generally acceptable or approved by a significant portion of the electric power generation industry in the relevant region, during the relevant period, as described in the immediate preceding sentence.
 - 1.31. "Required Facility Documents" means all licenses, permits, authorizations, agreements necessary for construction, operation, interconnection, maintenance of the Facility including without limitation those set forth in Exhibit B.
 - 1.32. "RPS Attributes" means all attributes related to the Net Output generated by the Facility that are required in order to provide PGE with "qualifying electricity," as that term is defined in Oregon's Renewable Portfolio Standard Act, Ore. Rev. Stat. 469A.010, in effect at the time of execution of this Agreement. RPS Attributes do not include Environmental Attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity and not needed to ensure that there are zero net emissions associated with the generation of electricity.
 - 1.33. "Schedule" shall mean PGE Schedule 201 filed with the Oregon Public Utilities Commission ("Commission") in effect on the Effective Date of this Agreement and attached hereto as Exhibit D, the terms of which are hereby incorporated by
 - 1.34. "Senior Lien" means a prior lien which has precedence as to the property reference. under the lien over another lien or encumbrance
 - 1.35. "Start-Up Lost Energy Value" means for the period after the date specified in Section 2.2.2 but prior to achievement of the Commercial Operation Date: zero, unless the Net Output is less than the pro-rated Pre-Commercial Operation Date Minimum Net Output for the applicable delay period, and the time-weighted average of the delay period's Mid-C Index Price for On-Peak Hours and Off-Peak Hours is greater

than the time-weighted average of the delay period's Contract Price for On-Peak Hours and Off-Peak Hours, in which case Startup Lost Energy Value equals: (pro-rated Pre-Commercial Operation Date Minimum Net Output for the applicable period - Net Output for the applicable period) X (the lower of: the time-weighted average of the Contract Price for On-Peak hours and Off-Peak Hours during the applicable period; or (the timeweighted average of the Mid-C Index Price for On-Peak Hours and Off-Peak Hours during the applicable period – the time-weighted average of the Contract Price for On-Peak Hours and Off-Peak Hours during the applicable period)). The time-weighted average in this section will reflect the relative proportions of On-Peak Hours and Off-

- 1.36. "Start-Up Testing" means the completion of applicable required factory Peak Hours in each day. and start-up tests as set forth in Exhibit C.
- 1.37. "Step-in Rights" means the right of one party to assume an intervening position to satisfy all terms of an agreement in the event the other party fails to perform its obligations under the agreement.
- 1.38. "Term" shall mean the period beginning on the Effective Date and ending
- 1.39. "Test Period" shall mean a period of sixty (60) days or a commercially on the Termination Date. reasonable period determined by the Seller.
- 1.40. "Transmission Agreement" means an agreement executed by the Seller and the Transmission Provider(s) for Transmission Services.
- 1.41. "Transmission Curtailment" means a limitation on Seller's ability to deliver any portion of the scheduled energy to PGE due to the unavailability of transmission to the Point of Delivery (for any reason other than Force Majeure).
- 1.42. "Transmission Curtailment Replacement Energy Cost" means the greater of zero or the amount calculated as: ((Mid-C Index Price - Contract Price) X curtailed energy) for periods of Transmission Curtailment.
 - 1.43. "Transmission Provider(s)" means the signatory (other than the Seller) to
 - 1.44. "Transmission Services" means any and all services (including but not the Transmission Agreement. limited to ancillary services and control area services) required for the firm transmission and delivery of Energy from the Facility to the Point of Delivery for a term not less than the Term of this Agreement.

References to Recitals, Sections, and Exhibits are to be the recitals, sections and exhibits of this Agreement.

SECTION 2: TERM; COMMERCIAL OPERATION DATE

This Agreement shall become effective upon execution by both Parties ("Effective Date").

- Time is of the essence of this Agreement, and Seller's ability to meet certain requirements prior to the Commercial Operation Date and to complete all requirements to establish the Commercial Operation Date is critically important. Therefore,
 - 2.2.1. By March 1, 2020 Seller shall begin initial deliveries of Net Output; and
 - 2.2.2 By March 31, 2020 Seller shall have completed all requirements under Section 1.5 and shall have established the Commercial Operation Date.
 - 2.2.3. Unless the Parties agree in writing that a later Commercial Operation Date is reasonable and necessary, the Commercial Operation Date shall be no more than three (3) years from the Effective Date. PGE will not unreasonably withhold agreement to a Commercial Operation Date that is more than three (3) years from the Effective date if the Seller has demonstrated that a later Commercial Operation Date is
 - This Agreement shall terminate on the date 18 years after the effective reasonable and necessary. date, or the date the Agreement is terminated in accordance with Section 8 or 11, whichever is earlier ("Termination Date").

SECTION 3: REPRESENTATIONS AND WARRANTIES

- Seller and PGE represent, covenant, and warrant as follows:
- 3.1.1. Seller warrants it is a Limited Liability Company duly organized under
- 3.1.2. Seller warrants that the execution and delivery of this Agreement does not the laws of **Delaware**. contravene any provision of, or constitute a default under, any indenture, mortgage, or other material agreement binding on Seller or any valid order of any court, or any regulatory agency or other body having authority to which Seller is subject.
 - 3.1.3. Seller warrants that the Facility is and shall for the Term of this Agreement continue to be a "Qualifying Facility" ("QF") as that term is defined in the version of 18 C.F.R. Part 292 in effect on the Effective Date. Seller has provided the appropriate QF certification, which may include a Federal Energy Regulatory Commission ("FERC") self-certification to PGE prior to PGE's execution of this Agreement. At any time during the Term of this Agreement, PGE may require Seller to provide PGE with evidence satisfactory to PGE in its reasonable discretion that the Facility continues to qualify as a QF under all applicable requirements.
 - 3.1.4. Seller warrants that it has not within the past two (2) years been the debtor in any bankruptcy proceeding, and Seller is and will continue to be for the Term of this Agreement current on all of its financial obligations.
 - 3.1.5. Seller warrants that during the Term of this Agreement, all of Seller's right, title and interest in and to the Facility shall be free and clear of all liens and encumbrances other than liens and encumbrances arising from third-party financing of the Facility other than workers', mechanics', suppliers' or similar liens, or tax liens, in each case arising in the ordinary course of business that are either not yet due and

Schedule 201

Standard Renewable Off-System Variable Power Purchase Agreement

payable or that have been released by means of a performance bond acceptable to PGE posted within eight (8) calendar days of the commencement of any proceeding to

- 3.1.6. Seller warrants that it will design and operate the Facility consistent with foreclose the lien.
- 3.1.7. Seller warrants that the Facility has a Nameplate Capacity Rating not Prudent Electrical Practices. greater than 10,000 kW.
 - 3.1.8. Seller warrants that Net Dependable Capacity of the Facility is 10,000 kW.
 - 3.1.9. Seller estimates that the average annual Net Output to be delivered by the Facility to PGE is 21,900,000 kilowatt-hours ("kWh"), which amount PGE will include in
 - 3.1.10. Seller represents and warrants that the Facility shall achieve the its resource planning. following Mechanical Availability Percentages ("Guarantee of Mechanical Availability"):
 - 3.1.10.1. Ninety percent (90%) beginning in the first Contract Year and extending through the Term for the Facility, if the Facility was operational and sold electricity to PGE or another buyer prior to the Effective Date of this Agreement; or
 - 3.1.10.2. Ninety percent (90%) beginning in Contract Year three and extending
 - 3.1.10.3. Annually, within 90 days of the end of each Contract Year, Seller shall throughout the remainder of the Term. send to PGE a detailed written report demonstrating and providing evidence of the actual MAP for the previous Contract Year.
 - 3.1.10.4. Seller's failure to meet the Guarantee of Mechanical Availability in a Calendar Year shall result in damages payable to PGE by Seller equal to the Lost Energy Value. PGE shall bill Seller for such damages in accordance with Section 7.
 - 3.1.11. Seller will deliver from the Facility to PGE at the Point of Delivery Net Output not to exceed a maximum of 33,750,000 kWh of Net Output during each Contract Year ("Maximum Net Output"). The cost of delivering energy from the Facility to PGE is the sole responsibility of the Seller.
 - 3.1.12. By the Commercial Operation Date, Seller has entered into a Generation Interconnection Agreement for a term not less than the term of this Agreement.
 - 3.1.13. PGE warrants that it has not within the past two (2) years been the debtor in any bankruptcy proceeding, and PGE is and will continue to be for the Term of this Agreement current on all of its financial obligations.
 - 3.1.14 Seller warrants that the Facility satisfies the eligibility requirements specified in the Definition of a Small Cogeneration Facility or Small Power Production Facility Eligible to Receive the Standard Renewable Rates and Standard Renewable PPA in PGE's Schedule and Seller will not make any changes in its ownership, control or management during the term of this Agreement that would cause it to not be in compliance with the Definition of a Small Cogeneration Facility or Small Power

Production Facility Eligible to Receive the Standard Renewable Rates and Standard Renewable PPA in PGE's Schedule. Seller will provide, upon request by PGE not more frequently than every 36 months, such documentation and information as may be reasonably required to establish Seller's continued compliance with such Definition. PGE agrees to take reasonable steps to maintain the confidentiality of any portion of the above described documentation and information that the Seller identifies as confidential except PGE will provide all such confidential information to the Commission upon the

3.1.15. Seller warrants that it will comply with all requirements necessary for all Commission's request. Transferred RECs (as defined in Section 4.5) associated with Net Output to be issued, monitored, accounted for, and transferred by and through the Western Renewable Energy Generation System consistent with the provisions of OAR 330-160-0005 through OAR 330-160-0050. PGE warrants that it will reasonably cooperate in Seller's efforts to meet such requirements, including, for example serving as the qualified reporting entity for the Facility if the Facility is located in PGE's balancing authority.

SECTION 4: DELIVERY OF POWER, PRICE AND ENVIRONMENTAL ATTRIBUTES

- Commencing on the Effective Date and continuing through the Term of this Agreement, Seller shall sell to PGE the entire Net Output delivered from the Facility at the Point of Delivery.
 - PGE shall pay Seller the Contract Price for all delivered Net Output.
- Upon completion of construction of the Facility, Seller shall provide PGE an As-built Supplement to specify the actual Facility as built. Seller shall not increase the Nameplate Capacity Rating above that specified in Exhibit A or increase the ability of the Facility to deliver Net Output in quantities in excess of the Net Dependable Capacity, or the Maximum Net Output as described in Section 3.1.11 above, through any means including, but not limited to, replacement, modification, or addition of existing equipment, except with prior written notice to PGE. In the event Seller increases the Nameplate Capacity Rating of the Facility to no more than 10,000 kW pursuant to this section, PGE shall pay the Contract Price for the additional delivered Net Output. In the event Seller increases the Nameplate Capacity Rating to greater than 10,000 kW, then Seller shall be required to enter into a new power purchase agreement for all delivered Net Output proportionally related to the increase of Nameplate Capacity above 10,000
 - Seller shall provide preschedules for all deliveries of energy hereunder, including identification of receiving and generating control areas, by 9:00:00 PPT on the kW. last business day prior to the scheduled date of delivery. All energy shall be scheduled according to the most current North America Energy Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) scheduling rules and practices. The respective representatives shall maintain coordination; provided, however, that in the absence of such coordination, the hourly schedule established by the exchange of preschedules shall be considered final. Seller and PGE shall maintain records of hourly energy schedules for accounting and

operating purposes. The final E-Tag shall be the controlling evidence of the Parties' schedule. All energy shall be prescheduled according to customary WECC scheduling practices. Seller shall make commercially reasonable efforts to schedule in any hour an amount equal to its expected Net Output for such hour. Seller shall maintain a minimum of two years records of Net Output and shall agree to allow PGE to have access to such records and to imbalance information kept by the Transmission Provider.

From the start of the Renewable Resource Deficiency Period through the remainder of the Term of this Agreement, Seller shall provide and PGE shall acquire the RPS Attributes for the Contract Years as specified in the Schedule and Seller shall retain ownership of all other Environmental Attributes (if any). During the Renewable Resource Sufficiency Period, Seller shall retain all Environmental Attributes in accordance with the Schedule. The Contract Price includes full payment for the Net Output and any RPS Attributes transferred to PGE under this Agreement. With respect to Environmental Attributes not transferred to PGE under this Agreement ("Seller-Retained Environmental Attributes") Seller may report under §1605(b) of the Energy Policy Act of 1992 or under any applicable program as belonging to Seller any of the Seller-Retained Environmental Attributes, and PGE shall not report under such program that such Seller-Retained Environmental Attributes belong to it. With respect to RPS Attributes transferred to PGE under this Agreement ("Transferred RECs"), PGE may report under §1605(b) of the Energy Policy Act of 1992 or under any applicable program as belonging to it any of the Transferred RECs, and Seller shall not report under such program that such Transferred RECs belong to it.

SECTION 5: OPERATION AND CONTROL

- Seller shall operate and maintain the Facility in a safe manner in accordance with the Generation Interconnection Agreement, and Prudent Electrical Practices. PGE shall have no obligation to purchase Net Output from the Facility to the extent the interconnection of the Facility to PGE's electric system is disconnected, suspended or interrupted, in whole or in part, pursuant to the Generation Interconnection Agreement, or to the extent generation curtailment is required as a result of Seller's noncompliance with the Generation Interconnection Agreement. Seller is solely responsible for the operation and maintenance of the Facility. PGE shall not, by reason of its decision to inspect or not to inspect the Facility, or by any action or inaction taken with respect to any such inspection, assume or be held responsible for any liability or occurrence arising from the operation and maintenance by Seller of the
 - Seller agrees to provide sixty (60) days advance written notice of any Facility. scheduled maintenance that would require shut down of the Facility for any period of
 - If the Facility ceases operation for unscheduled maintenance, Seller time. immediately shall notify PGE of the necessity of such unscheduled maintenance, the time when such maintenance has occurred or will occur, and the anticipated duration of such maintenance. Seller shall take all reasonable measures and exercise its best

efforts to avoid unscheduled maintenance, to limit the duration of such unscheduled maintenance, and to perform unscheduled maintenance during Off-Peak hours.

SECTION 6: CREDITWORTHINESS

In the event Seller: a) is unable to represent or warrant as required by Section 3 that it has not been a debtor in any bankruptcy proceeding within the past two (2) years; b) becomes such a debtor during the Term; or c) is not or will not be current on all its financial obligations, Seller shall immediately notify PGE and shall promptly (and in no less than 10 days after notifying PGE) provide default security in an amount reasonably acceptable to PGE in one of the following forms: Senior Lien, Step-in Rights, a Cash The amount of such default security that shall be acceptable to PGE shall be equal to: (annual On Peak Hours) X (On Peak Price - Off Peak Price) X (Net Dependable Capacity). Notwithstanding the foregoing, in the event Seller is not current on construction related financial obligations, Seller shall notify PGE of such delinquency and PGE may, in its discretion, grant an exception to the requirements to provide default security if the QF has negotiated financial arrangements with the construction loan lender that mitigate Seller's financial risk to PGE.

SECTION 7: BILLINGS, COMPUTATIONS AND PAYMENTS

- On or before the thirtieth (30th) day following the end of each Billing Period, PGE shall send to Seller payment for Seller's deliveries of Net Output to PGE, together with computations supporting such payment. payment to reflect amounts owing from Seller to PGE pursuant to this Agreement and any other agreement related to the Facility between the Parties or otherwise. On or before the thirtieth (30th) day following the end of each Contract Year, PGE shall bill for any Lost Energy Value accrued pursuant to this Agreement.
 - Any amounts owing after the due date thereof shall bear interest at the Prime Rate plus two percent (2%) from the date due until paid; provided, however, that the interest rate shall at no time exceed the maximum rate allowed by applicable law.

SECTION 8: DEFAULT, REMEDIES AND TERMINATION

- In addition to any other event that may constitute a default under this Agreement, the following events shall constitute defaults under this Agreement:
- 8.1.1. Breach by Seller or PGE of a representation or warranty, except for Section 3.1.4, set forth in this Agreement.
- 8.1.2. Seller's failure to provide default security, if required by Section 6, prior to delivery of any Net Output to PGE or within 10 days of notice.
- 8.1.3. Seller's failure to meet the Guarantee of Mechanical Availability established in Section 3.1.10 for two consecutive Contract Years or Seller's failure to provide any written report required by that section.
 - 8.1.4. If Seller is no longer a Qualifying Facility.
 - 8.1.5. Failure of PGE to make any required payment pursuant to Section 7.1.

- 8.1.6. Seller's failure to meet the Commercial Operation Date.
- In the event of a default under Section 8.1.6, PGE may provide Seller with written notice of default. Seller shall have one year in which to cure the default during which time the Seller shall pay PGE damages equal to the Lost Energy Value. If Seller is unable to cure the default, PGE may immediately terminate this Agreement as provided in Section 8.3. PGE's resource sufficiency/deficiency position shall have no bearing on PGE's right to terminate the Agreement under this Section 8.2.
 - In the event of a default hereunder, except as otherwise provided in this Agreement, the non-defaulting party may immediately terminate this Agreement at its sole discretion by delivering written notice to the other Party. In addition, the nondefaulting Party may pursue any and all legal or equitable remedies provided by law or pursuant to this Agreement including damages related to the need to procure A termination hereunder shall be effective upon the date of delivery of notice, as provided in Section 20. The rights provided in this Section 8 are cumulative such that the exercise of one or more rights shall not constitute a waiver of
 - If this Agreement is terminated as provided in this Section 8, PGE shall any other rights. make all payments, within thirty (30) days, that, pursuant to the terms of this Agreement, are owed to Seller as of the time of receipt of notice of default. PGE shall not be required to pay Seller for any Net Output delivered by Seller after such notice of default.
 - In the event PGE terminates this Agreement pursuant to this Section 8, and Seller wishes to again sell Net Output to PGE following such termination, PGE in its sole discretion may require that Seller shall do so subject to the terms of this Agreement, including but not limited to the Contract Price until the Term of this Agreement (as set forth in Section 2.3) would have run in due course had the Agreement remained in effect. At such time Seller and PGE agree to execute a written document ratifying the terms of this Agreement.
 - Sections 8.1, 8.4, 8.5, 10, and 19.2 shall survive termination of this 8.6. Agreement.

SECTION 9: TRANSMISSION CURTAILMENTS

- Seller shall give PGE notice as soon as reasonably practicable of any Transmission Curtailment that is likely to affect Seller's ability to deliver any portion of energy scheduled pursuant to Section 4.4 of this Agreement.
- If as the result of a Transmission Curtailment, Seller does not deliver any portion of energy (including real-time adjustments), scheduled pursuant to Section 4.4 of this Agreement, Seller shall pay PGE the Transmission Curtailment Replacement Energy Cost for the number of MWh of energy reasonably determined by PGE as the difference between (i) the scheduled energy that would have been delivered to PGE under this Agreement during the period of Transmission Curtailment and (ii) the actual energy, if any, that was delivered to PGE for the period.

SECTION 10: INDEMNIFICATION AND LIABILITY

- 10.1. Seller agrees to defend, indemnify and hold harmless PGE, its directors, officers, agents, and representatives against and from any and all loss, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with Seller's delivery of electric power to PGE or with the facilities at or prior to the Point of Delivery, or otherwise arising out of this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PGE, Seller or others, excepting to the extent such loss, claim, action or suit may be caused by the negligence of PGE, its directors, officers, employees, agents or representatives.
 - 10.2. PGE agrees to defend, indemnify and hold harmless Seller, its directors, officers, agents, and representatives against and from any and all loss, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with PGE's receipt of electric power from Seller or with the facilities at or after the Point of Delivery, or otherwise arising out of this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PGE, Seller or others, excepting to the extent such loss, claim, action or suit may be caused by the negligence of Seller, its directors, officers, employees, agents or representatives.
 - 10.3. Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a Party to this Agreement. No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or to the public, nor affect the status of PGE as an independent public utility corporation or Seller as an independent individual or entity.
 - 10.4. NEITHER PARTY SHALL BE LIABLE TO THE OTHER FOR SPECIAL, PUNITIVE, INDIRECT OR CONSEQUENTIAL DAMAGES, WHETHER ARISING FROM CONTRACT, TORT (INCLUDING NEGLIGENCE), STRICT LIABILITY OR OTHERWISE.

SECTION 11: INSURANCE

11.1. Prior to the connection of the Facility to PGE's electric system, provided such Facility has a design capacity of 200 kW or more, Seller shall secure and continuously carry for the Term hereof, with an insurance company or companies rated not lower than "B+" by the A. M. Best Company, insurance policies for bodily injury and property damage liability. Such insurance shall include provisions or endorsements naming PGE, it directors, officers and employees as additional insureds; provisions that such insurance is primary insurance with respect to the interest of PGE and that any insurance or self-insurance maintained by PGE is excess and not contributory insurance with the insurance required hereunder; a cross-liability or severability of

insurance interest clause; and provisions that such policies shall not be canceled or their limits of liability reduced without thirty (30) days' prior written notice to PGE. Initial limits of liability for all requirements under this section shall be \$1,000,000 million single limit, which limits may be required to be increased or decreased by PGE as PGE determines in its reasonable judgment economic conditions or claims experience may

- 11.2. Prior to the connection of the Facility to PGE's electric system, provided such facility has a design capacity of 200 kW or more, Seller shall secure and warrant. continuously carry for the Term hereof, in an insurance company or companies rated not lower than "B+" by the A. M. Best Company, insurance acceptable to PGE against property damage or destruction in an amount not less than the cost of replacement of the Facility. Seller promptly shall notify PGE of any loss or damage to the Facility. Unless the Parties agree otherwise, Seller shall repair or replace the damaged or destroyed Facility, or if the facility is destroyed or substantially destroyed, it may terminate this Agreement. Such termination shall be effective upon receipt by PGE of written notice from Seller. Seller shall waive its insurers' rights of subrogation against PGE regarding Facility property losses.
 - 11.3. Prior to the connection of the Facility to PGE's electric system and at all other times such insurance policies are renewed or changed, Seller shall provide PGE with a copy of each insurance policy required under this Section, certified as a true copy by an authorized representative of the issuing insurance company or, at the discretion of PGE, in lieu thereof, a certificate in a form satisfactory to PGE certifying the issuance of such insurance. If Seller fails to provide PGE with copies of such currently effective insurance policies or certificates of insurance, PGE at its sole discretion and without limitation of other remedies, may upon ten (10) days advance written notice by certified or registered mail to Seller either withhold payments due Seller until PGE has received such documents, or purchase the satisfactory insurance and offset the cost of obtaining such insurance from subsequent power purchase payments under this Agreement.

SECTION 12: FORCE MAJEURE

12.1. As used in this Agreement, "Force Majeure" or "an event of Force Majeure" means any cause beyond the reasonable control of the Seller or of PGE which, despite the exercise of due diligence, such Party is unable to prevent or overcome. By way of example, Force Majeure may include but is not limited to acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes, and other labor disturbances, earthquakes, fires, lightning, epidemics, sabotage, restraint by court order or other delay or failure in the performance as a result of any action or inaction on behalf of a public authority which by the exercise of reasonable foresight such Party could not reasonably have been expected to avoid and by the exercise of due diligence, it shall be unable to overcome, subject, in each case, to the requirements of the first sentence of this paragraph. Force Majeure, however, specifically excludes the cost or availability of resources to operate the Facility, changes in market conditions that affect

the price of energy or transmission, wind or water droughts, and obligations for the

- If either Party is rendered wholly or in part unable to perform its payment of money when due. obligation under this Agreement because of an event of Force Majeure, that Party shall be excused from whatever performance is affected by the event of Force Majeure to the extent and for the duration of the Force Majeure, after which such Party shall recommence performance of such obligation, provided that:
 - 12.2.1. the non-performing Party, shall, promptly, but in any case within one (1) week after the occurrence of the Force Majeure, give the other Party written notice describing the particulars of the occurrence; and
 - 12.2.2. the suspension of performance shall be of no greater scope and of no longer duration than is required by the Force Majeure; and
 - 12.2.3. the non-performing Party uses its best efforts to remedy its inability to perform its obligations under this Agreement.
 - 12.3. No obligations of either Party which arose before the Force Majeure causing the suspension of performance shall be excused as a result of the Force
 - 12.4. Neither Party shall be required to settle any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the Majeure. dispute, are contrary to the Party's best interests.

SECTION 13: SEVERAL OBLIGATIONS

Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership or joint venture or to impose a trust or partnership duty, obligation or liability between the Parties. If Seller includes two or more parties, each such party shall be jointly and severally liable for Seller's obligations under this Agreement.

SECTION 14: CHOICE OF LAW

This Agreement shall be interpreted and enforced in accordance with the laws of the state of Oregon, excluding any choice of law rules which may direct the application of the laws of another jurisdiction.

SECTION 15: PARTIAL INVALIDITY AND PURPA REPEAL

It is not the intention of the Parties to violate any laws governing the subject matter of this Agreement. If any of the terms of the Agreement are finally held or determined to be invalid, illegal or void as being contrary to any applicable law or public policy, all other terms of the Agreement shall remain in effect. If any terms are finally held or determined to be invalid, illegal or void, the Parties shall enter into negotiations concerning the terms affected by such decision for the purpose of achieving conformity with requirements of any applicable law and the intent of the Parties to this Agreement.

In the event the Public Utility Regulatory Policies Act (PURPA) is repealed, this Agreement shall not terminate prior to the Termination Date, unless such termination is mandated by state or federal law.

SECTION 16: WAIVER

Any waiver at any time by either Party of its rights with respect to a default under this Agreement or with respect to any other matters arising in connection with this Agreement must be in writing, and such waiver shall not be deemed a waiver with respect to any subsequent default or other matter.

SECTION 17: GOVERNMENTAL JURISDICTION AND AUTHORIZATIONS

This Agreement is subject to the jurisdiction of those governmental agencies having control over either Party or this Agreement. Seller shall at all times maintain in effect all local, state and federal licenses, permits and other approvals as then may be required by law for the construction, operation and maintenance of the Facility, and shall provide upon request copies of the same to PGE.

SECTION 18: SUCCESSORS AND ASSIGNS

This Agreement and all of the terms hereof shall be binding upon and inure to the benefit of the respective successors and assigns of the Parties. No assignment hereof by either Party shall become effective without the written consent of the other Party being first obtained and such consent shall not be unreasonably withheld. Notwithstanding the foregoing, either Party may assign this Agreement without the other Party's consent as part of (a) a sale of all or substantially all of the assigning Party's assets, or (b) a merger, consolidation or other reorganization of the assigning Party.

SECTION 19: ENTIRE AGREEMENT

- proposals, agreements, representations, negotiations, discussions or letters, whether oral or in writing, regarding prior PGE's purchase of Net Output from the Facility. No modification of this Agreement shall be effective unless it is in writing and signed by both Parties.
- 19.2. By executing this Agreement, Seller releases PGE from any third party claims related to the Facility, known or unknown, which may have arisen prior to the Effective Date.

SECTION 20: NOTICES

20.1. All notices except as otherwise provided in this Agreement shall be in writing, shall be directed as follows and shall be considered delivered in person or when deposited in the U.S. Mail, postage prepaid by certified or registered mail and return receipt requested:

Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

To Seller:	Blue Marmot VII LLCc/o EDP Renewables NorAttention: General Couns808 Travis Suite 808Houston, TX 77002	sel.
with a copy to:		
To PGE:	Contracts Manager QF Contracts, 3WTC0306 PGE - 121 SW Salmon S Portland, Oregon 97204	addressed.
or their addresses, by	ties may change the person to y providing written notices the WHEREOF, the Parties hereto pective names as of the Effecti	o whom such notices are addressed, reof in accordance with this Section to have caused this Agreement to be live Date.
PGE By: Name: Title: Date:		Approved By: Business Terms Credit Legal
Blue Marmot VII LL (Name Seller) By: Name: Ster Title: Executive Date Setern and Centr	/e Irvin	Risk Mgt.

Brian Hayes Executive Vice President, Asset Operations

A-1

Schedule 201
Standard Renewable Off-System Variable Power Purchase Agreement
Form Effective August 12, 2016

EXHIBIT A DESCRIPTION OF SELLER'S FACILITY

The facility will be a solar PV plant consisting of 38,715 polycrystalline modules of nominal 335W rating each. Total plant rating will be 12.970 MWdc/10MWac. Modules will be mounted to single-axis trackers.

Central inverter stations will be located at intermediate points in the PV field.

Modules will be evenly distributed to the inverter stations. The total inverter nameplate rating will be 10.0MWac. Each inverter will be directly coupled to a 34.5kV step-up transformer. The transformers will be connected to a 34.5kV AC collection system, which will feed into the plant switchgear.

The plant switchgear will feed a 34.5kV transmission line, which will run overhead approximately 6.5 miles to the PacifiCorp Mile-Hi Substation.

Inside the Mile-Hi Substation, the transmission line will connect to a new bay containing a facility-owned 34.5kV/115kV GSU transformer, associated breakers, switching, bus, and controls.

The facility-owned components at Mile-Hi substation are considered part of the self-certified qualifying facility.

Note this information is considered representative design information which is to be updated at the time of project construction and is subject to design finalization

Solar Facility Characteristics:

1. Generation
a. PvSyst (or equivalent) simulation results detail, including but not limited to:
i. Annual MWh (AC) for the first calendar year of commercial operation
ii. Annual degradation factor
iii. Average 24-hr profile of generation MWh (AC) for each month during the first calendar year
iv. Expected Solar Capacity Factor
v. Maximum annual output (monthly MWh detail)
iv Loss Diagram v. Maximum amu iv. Loss Diagram
2. Description of Modules:
a. Module type
b. #of modules
c. Max power voltage
d. Max power urrent
e. Max system voltage
f. Total DC system site
3. Description of Racking
a. Racking

e. Max system voltage
f. Total DC system site
3. Description of Racking
a. Racking
l. Type: (fixed tilt, single-axis tracking, or dual-axis tracking, etc.)
ii. Tilt angle (if tixed-tilt)
iii. Azimuth (default a south-acing)
4. Description of Inverters:
a. Number of Inverters
b. Model
c. Maximum Prower (RW)
d. Operating Voltage (VAC)
e. Max. Output Current (A)
f. Rateo DC Voltage
g. Rated DC Current
h. Maximum Output (RW)
g. Facility AC Capacity Rating
h. Inverter loading ratio
l. Facility AC rating
D. Description of transformers
inverter U-MV
a. to dransformers
b. Model
c. High Voltage Rating
d. Low Voltage Rating
f. Hop Voltage connection
g. Low Voltage connection
g. Low Voltage Rating
d. Ligh Voltage Rating
d. Ligh Voltage Rating
d. Ligh Voltage Rating
d. Ligh Voltage Rating
f. High Voltage Connection
g. Low Voltage Connection
g. Low Voltage Connection
g. Low Voltage Connection
g. Low Voltage Connection

6. Description of metering, communications, and monitoring

See tab "Generation" 27% See tab "Generation" See tab "Generation"

Polycrystalline Silicon 38,715 37.4V 8.97A 1500V 12970kW

Single-Axis Tracking

N/A

South-Facing

S ABB PVS980-58-1818kVA-6 2910kW DC 600 1925A 1500 1945 2000 10.0MW 1.297 10.0MW

> 5 ABB PadPlus+ 34,500 600 2.0 each, 10.0 total Wye-Ground Wye

ABB 10MVA 115,000 34,500 10/12.5 ONAF

Delta
Delta
Meter shall be revenue-grade, located at POI. POI shall be slack bus
on the high-side bushing of plant GSU transformer at Mile Hi
Substation. Revenue meter shall transmit real-time data pulses
(instantaneous MW, MAR, KWH) to Operator's billing data
program. Customer's 35kV switchgear at Mile Hi shall be fitted with
Customer meter as an alternate data source. Breakers and relays
at Customer's PV plant shall connect to operator ScADA system at
Mile Hi substation via OPGW run on proposed Customer
Meter Hi substation via OPGW run on proposed Customer
Metering equipment and accessiones, communication battery
system, fiber optic network device and SCADA RTU (Bemote
System, fiber optic network device and SCADA RTU (Bemote
Terminal Unit) in oxisting Mile Hi relay/control buildings to control,
monitor, and transmit data to Operator and back to PV plant
SCADA.

Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

7. Description of station service requirements

15KVA, 240/120V 1-phase service at PV plant substation for Relay/SCADA/O&M building and plant accessory loads. 5KVA, 240/120V 1-phase at Mile HI substation for Customer controls

Transmission line shall be new radial line consisting of 34.5KV ACSR, 1-conductor per phase with OPGW on wood poles, approx. 6.5 miles. Line will originate at PV plant 34.5kV main switchgear and terminate at dead-end structure feeding a new 35kV breaker at Mile Hi Substation. 35kV breaker will feed new GSU and new 115kV breaker at Mile Hi Substation. POI shall be slack bus between new 115kV breaker and existing 115kV bus at Mile Hi Substation.

Seller is taking necessary steps to execute required interconnection and transmission agreements prior to commercial operation date.

9. Transaction Service Request Number, Interconnection Queue number, and System impact/interconnection study document: Seller is taking necessary steps to execute required interconnection and transmission agreements prior to commercial operation date.

EXHIBIT B REQUIRED FACILITY DOCUMENTS

Sellers Generation Interconnection Agreement

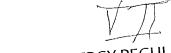
Transmission Service Agreement with PacifiCorp

Lease agreement

Conditional Use Permit issued by Lake County

Any additional permits that might be required by Lake County or Oregon Department of Environmental Quality, including access permit, building and electric permits, and storm water prevention permit

FERC Qualifying Facility self-certification



FEDERAL ENERGY REGULATORY COMMISSION WASHINGTON, DC

OMB Control # 1902-0075 Expiration 06/30/2019

Form 556 Certification of Qualifying Facility (QF) Status for a Small Power Production or Cogeneration Facility

General

Questions about completing this form should be sent to Form556@ferc.gov. Information about the Commission's QF program, answers to frequently asked questions about QF requirements or completing this form, and contact information for QF program staff are available at the Commission's QF website, <u>www.ferc.gov/QF</u>. The Commission's QF website also provides links to the Commission's QF regulations (18 C.F.R. § 131.80 and Part 292), as well as other statutes and orders pertaining to the Commission's QF program.

Who Must File

Any applicant seeking QF status or recertification of QF status for a generating facility with a net power production capacity (as determined in lines 7a through 7g below) greater than 1000 kW must file a self-certification or an application for Commission certification of QF status, which includes a properly completed Form 556. Any applicant seeking QF status for a generating facility with a net power production capacity 1000 kW or less is exempt from the certification requirement, and is therefore not required to complete or file a Form 556. See 18 C.F.R. § 292.203.

How to Complete the Form 556

This form is intended to be completed by responding to the items in the order they are presented, according to the instructions given. If you need to back-track, you may need to clear certain responses before you will be allowed to change other responses made previously in the form. If you experience problems, click on the nearest help button () for assistance, or contact Commission staff at Form556@ferc.gov.

Certain lines in this form will be automatically calculated based on responses to previous lines, with the relevant formulas shown. You must respond to all of the previous lines within a section before the results of an automatically calculated field will be displayed. If you disagree with the results of any automatic calculation on this form, contact Commission staff at Form 556@ferc.gov to discuss the discrepancy before filing.

You must complete all lines in this form unless instructed otherwise. Do not alter this form or save this form in a different format. Incomplete or altered forms, or forms saved in formats other than PDF, will be rejected.

How to File a Completed Form 556

Applicants are required to file their Form 556 electronically through the Commission's eFiling website (see instructions on page 2). By filing electronically, you will reduce your filing burden, save paper resources, save postage or courier charges, help keep Commission expenses to a minimum, and receive a much faster confirmation (via an email containing the docket number assigned to your facility) that the Commission has received your filing.

If you are simultaneously filing both a waiver request and a Form 556 as part of an application for Commission certification, see the "Waiver Requests" section on page 3 for more information on how to file.

Paperwork Reduction Act Notice

This form is approved by the Office of Management and Budget. Compliance with the information requirements established by the FERC Form No. 556 is required to obtain or maintain status as a QF. See 18 C.F.R. § 131.80 and Part 292. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The estimated burden for completing the FERC Form No. 556, including gathering and reporting information, is as follows: 3 hours for self-certification of a small power production facility, 8 hours for self-certifications of a cogeneration facility, 6 hours for an application for Commission certification of a small power production facility, and 50 hours for an application for Commission certification of a cogeneration facility. Send comments regarding this burden estimate or any aspect of this collection of information, including suggestions for reducing this burden, to the following: Information Clearance Officer, Office of the Executive Director (ED-32), Federal Energy Regulatory Commission, 888 First Street N.E., Washington, DC 20426 (<u>DataClearance@ferc.gov</u>); and Desk Officer for FERC, Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (oira submission@omb.eop.gov). Include the Control No. 1902-0075 in any correspondence.

To electronically file your Form 556, visit the Commission's QF website at www.ferc.gov/QF and click the eFiling link. Electronic Filing (eFiling)

If you are eFiling your first document, you will need to register with your name, email address, mailing address, and phone number. If you are registering on behalf of an employer, then you will also need to provide the employer name, alternate contact name, alternate contact phone number and and alternate contact email.

Once you are registered, log in to eFiling with your registered email address and the password that you created at registration. Follow the instructions. When prompted, select one of the following QF-related filing types, as appropriate,

ne ciectite or	eral filing category.	Description
siting sategory	Filing Type as listed in eFiling	Use to submit an application for
Filing category	(Fee) Application for Commission Cert. as Cogeneration QF	Commission certification of a Commission recertification of a Cogeneration facility as a QF.
	(Fee) Application for Commission Cert. as Small Power QF	Commission certification of a Commission recertification of a small power production facility as a
	Self-Certification Notice (QF, EG, FC)	Use to submit a notice of self- certification of your facility (cogeneration or small power production) as a QF.
Electric	Self-Recertification of Qualifying Facility (QF)	Use to submit a notice of self-recertification of your facility (cogeneration or small power production) as a QF. Use to correct or supplement a
	Supplemental Information or Request	Use to correct or supplements Form 556 that was submitted with errors or omissions, or for which Commission staff has requested additional information. Do not u this filing type to report new changes to a facility or its ownership; rather, use a self- recertification or Commission recertification to report such changes. Use to submit a petition for declaratory order granting a way
General	(Fee) Petition for Declaratory Order (not under FPA F	of Commission QF regulations pursuant to 18 C.F.R. §§ 292.20

You will be prompted to submit your filing fee, if applicable, during the electronic submission process. Filing fees can be paid via electronic bank account debit or credit card.

During the eFiling process, you will be prompted to select your file(s) for upload from your computer.

Filing Fee

No filing fee is required if you are submitting a self-certification or self-recertification of your facility as a QF pursuant to 18 C.F.R. § 292.207(a).

- (1) an application for Commission certification or recertification of your facility as a QF pursuant to 18 C.F.R. § 292.207(b), or A filing fee is required if you are filing either of the following:
 - (2) a petition for declaratory order granting waiver pursuant to 18 C.F.R. §§ 292.204(a)(3) and/or 292.205(c).

The current fees for applications for Commission certifications and petitions for declaratory order can be found by visiting the Commission's QF website at www.ferc.gov/QF and clicking the Fee Schedule link.

You will be prompted to submit your filing fee, if applicable, during the electronic filing process described on page 2.

Required Notice to Utilities and State Regulatory Authorities

Pursuant to 18 C.F.R. § 292.207(a)(ii), you must provide a copy of your self-certification or request for Commission certification to the utilities with which the facility will interconnect and/or transact, as well as to the State regulatory authorities of the states in which your facility and those utilities reside. Links to information about the regulatory authorities in various states can be found by visiting the Commission's QF website at <u>www.ferc.gov/QF</u> and clicking the Notice Requirements link.

What to Expect From the Commission After You File

An applicant filing a Form 556 electronically will receive an email message acknowledging receipt of the filing and showing the docket number assigned to the filing. Such email is typically sent within one business day, but may be delayed pending confirmation by the Secretary of the Commission of the contents of the filing.

An applicant submitting a self-certification of QF status should expect to receive no documents from the Commission, other than the electronic acknowledgement of receipt described above. Consistent with its name, a self-certification is a certification by the applicant itself that the facility meets the relevant requirements for QF status, and does not involve a determination by the Commission as to the status of the facility. An acknowledgement of receipt of a self-certification, in particular, does not represent a determination by the Commission with regard to the QF status of the facility. An applicant self-certifying may, however, receive a rejection, revocation or deficiency letter if its application is found, during periodic compliance reviews, not to comply with the relevant requirements.

An applicant submitting a request for Commission certification will receive an order either granting or denying certification of QF status, or a letter requesting additional information or rejecting the application. Pursuant to 18 C.F.R. § 292.207(b)(3), the Commission must act on an application for Commission certification within 90 days of the later of the filing date of the application or the filing date of a supplement, amendment or other change to the application.

Waiver Requests

18 C.F.R. § 292.204(a)(3) allows an applicant to request a waiver to modify the method of calculation pursuant to 18 C.F.R. § 292.204(a)(2) to determine if two facilities are considered to be located at the same site, for good cause. 18 C.F.R. § 292.205(c) allows an applicant to request waiver of the requirements of 18 C.F.R. §§ 292.205(a) and (b) for operating and efficiency upon a showing that the facility will produce significant energy savings. A request for waiver of these requirements must be submitted as a petition for declaratory order, with the appropriate filing fee for a petition for declaratory order. Applicants requesting Commission recertification as part of a request for waiver of one of these requirements should electronically submit their completed Form 556 along with their petition for declaratory order, rather than filing their Form 556 as a separate request for Commission recertification. Only the filing fee for the petition for declaratory order must be paid to cover both the waiver request and the request for recertification if such requests are made simultaneously.

18 C.F.R. § 292.203(d)(2) allows an applicant to request a waiver of the Form 556 filing requirements, for good cause. Applicants filing a petition for declaratory order requesting a waiver under 18 C.F.R. § 292,203(d)(2) do not need to complete or submit a Form 556 with their petition.

If a street address does not exist for your facility, then line 3c of the Form 556 requires you to report your facility's geographic Geographic Coordinates coordinates (latitude and longitude). Geographic coordinates may be obtained from several different sources. You can find links to online services that show latitude and longitude coordinates on online maps by visiting the Commission's QF webpage at <u>www.ferc.gov/QF</u> and clicking the Geographic Coordinates link. You may also be able to obtain your geographic coordinates from a GPS device, Google Earth (available free at http://earth.google.com), a property survey, various engineering or construction drawings, a property deed, or a municipal or county map showing property lines.

Filing Privileged Data or Critical Energy Infrastructure Information in a Form 556

The Commission's regulations provide procedures for applicants to either (1) request that any information submitted with a Form 556 be given privileged treatment because the information is exempt from the mandatory public disclosure requirements of the Freedom of Information Act, 5 U.S.C. § 552, and should be withheld from public disclosure; or (2) identify any documents containing critical energy infrastructure information (CEII) as defined in 18 C.F.R. § 388.113 that should not be

If you are seeking privileged treatment or CEII status for any data in your Form 556, then you must follow the procedures in 18 C.F.R. § 388.112. See www.ferc.gov/help/filing-guide/file-ceii.asp for more information.

Among other things (see 18 C.F.R. § 388.112 for other requirements), applicants seeking privileged treatment or CEII status for data submitted in a Form 556 must prepare and file both (1) a complete version of the Form 556 (containing the privileged and/or CEII data), and (2) a public version of the Form 556 (with the privileged and/or CEII data redacted). Applicants preparing and filing these different versions of their Form 556 must indicate below the security designation of this version of their document. If you are *not* seeking privileged treatment or CEII status for any of your Form 556 data, then you should not

Grepating and Mary are not seeking privileged deads
their document. If you are <i>not</i> seeking privileged treatments their document. If you are <i>not</i> seeking privileged treatments their document. If you are <i>not</i> seeking privileged treatments their documents. If you are <i>not</i> seeking privileged treatments their documents. If you are <i>not</i> seeking privileged treatments their documents. If you are <i>not</i> seeking privileged treatments their documents. If you are <i>not</i> seeking privileged treatments their documents. If you are <i>not</i> seeking privileged treatments their documents. If you are <i>not</i> seeking privileged treatments their documents are not seeking privileged treatments.
their document. If you are <i>not</i> seeking privileges their document. If you are <i>not</i> seeking privileges respond to any of the items on this page. **Respond to any of the items on this page. **Non-Public: Applicant is seeking privileged treatment and/or CEII status for data contained in the Form 556 lines **Non-Public: Applicant is seeking privileged treatment and/or CEII status for data, including the data that is redacted indicated below. This non-public version of the applicant's Form 556.
A relicant is seeking privileged treatment and/or can 556 contains all data, including the data
Non-Public: Applicant is seemed in the applicant's form as a seemed in the applicant as a seemed in the applican
indicated below. This person of the applicant's Form 556.
Non-Public: Applicant is seeking privileged treatment and/or CEII status for data contained in the Form 556 lines in the (separate) public version of the applicant's Form 556. Public (redacted): Applicant is seeking privileged treatment and/or CEII status for data contained in the Form 556 lines Public (redacted): Applicant is seeking privileged treatment and/or CEII status for data contained in the Form 556 lines Public (redacted): Applicant is seeking privileged treatment and/or CEII status for data contained in the Form 556 lines
Public (redacted): Applicant is seeking phylicants's Form 556 contains all data except
in the (separate) public version of the applicant's Form 556: in the (separate) public version of the applicant's Form 556 contains all data except for data from the lines Public (redacted): Applicant is seeking privileged treatment and/or CEII status for data contained in the Form 556 contains all data except for data from the lines indicated below. This public version of the applicants's Form 556 contains all data except for data from the lines indicated below. This public version of the applicants's Form 556 contains all data except for data from the lines
indicated below. This public versal indicated below, which has been redacted. indicated below, which has been redacted.
indicated below, which you are seeking p
indicated below. This public version indicated below, which has been redacted. indicated below, which has been redacted. Privileged: Indicate below which lines of your form contain data for which you are seeking privileged treatment.
Privileged. Indian
Critical Energy Infrastructure Information (CEII): Indicate below which lines of your form contain data for which you are
Laboration data for writer,
ture Information (CEII): Indicate below which was
Critical Energy Infrastructure information
seeking CEII status
300000
as applicable
the stift which versions of the electronic documents your

The eFiling process described on page 2 will allow you to identify which versions of the electronic documents you submit are public, privileged and/or CEII. The filenames for such documents should begin with "Public", "Priv", or "CEII", as applicable, to clearly indicate the security designation of the file. Both versions of the Form 556 should be unaltered PDF copies of the Form 556, as available for download from www.ferc.gov/QF. To redact data from the public copy of the submittal, simply omit the relevant data from the Form. For numerical fields, leave the redacted fields blank. For text fields, complete as much of the field as possible, and replace the redacted portions of the field with the word "REDACTED" in brackets. Be sure to identify above <u>all</u> fields which contain data for which you are seeking non-public status.

The Commission is not responsible for detecting or correcting filer errors, including those errors related to security designation. If your documents contain sensitive information, make sure they are filed using the proper security designation.

FEDERAL ENERGY REGULATORY COMMISSION WASHINGTON, DC

OMB Control # 1902-0075 Expiration 06/30/2019

	5 Il name of applicant	WASHINGTON Certification of Qualifying Production or Cogeneral (legal entity on whose behalf qualify	ing facility status i	is sought for this facility)	
1a 	lue Marmot VII I	.LC			
-	A - dicapt street addre	255			
116	308 Travis Stree	t #700			
			1d State/provi	ince	
-	City		TX		
	City Houston			1g Telephone number	
l l		1f Country (if not United States)		713-265-0350	ı
1	Postal code			No 🛛	
	77002	ity ever previously been certified as a	a Qr:		88
1	h Has the instant laci	ocket number of the last known QF fi	iling pertaining to	this facility: QF	1
1	Notice of self-cer	tification	Application for fee; see "Filing I	Commission certification (requires initing Fee" section on page 3) facility complies with the requirements for	
	QF status. A notic	te of self-certification does we to verify compliance. See the	ne "What to Expec	t From the Commission	
orma	notice of self-cert	cification to verify compliance. See the second sec	ic iiii		
Informa	notice of self-cert section on page 1k What type(s) of Q	cification to verify compliance. See to 3 for more information. F status is the applicant seeking for it It request production facility status	ts facility? (check a	all that apply) generation facility status	
tion Informa	notice of self-cert section on page 1k What type(s) of Q	cification to verify compliance. See to 3 for more information. F status is the applicant seeking for it It request production facility status	ts facility? (check a	all that apply) generation facility status	
cation Informa	of status. A notice notice of self-cert section on page 1k What type(s) of Q Qualifying sma 1l What is the purpo	cification to verify compliance. See to 3 for more information. If status is the applicant seeking for it Il power production facility status ose and expected effective date(s) of cation: facility expected to be installe	ts facility? (check a Qualifying coo this filing?	all that apply) generation facility status and to begin operation on 3/31/20	
pplication Informa	of status. A notice notice of self-cert section on page 1k What type(s) of Q Qualifying sma 1l What is the purpo	cification to verify compliance. See to 3 for more information. If status is the applicant seeking for it Il power production facility status ose and expected effective date(s) of cation: facility expected to be installe	ts facility? (check a Qualifying coo this filing?	all that apply) generation facility status and to begin operation on 3/31/20	
Application Informa	OF status. A floor notice of self-cert section on page 1k What type(s) of O Qualifying sma 1l What is the purpo Original certifi Change(s) to a (identify type	iffication to verify compliance. See to a for more information. F status is the applicant seeking for it also be and expected effective date(s) of cation; facility expected to be installed a previously certified facility to be effective and describe a previously certified facility to be effective and describe and d	ts facility? (check a Qualifying count this filing? ed by3/1/20 ective onchange(s) in the Mange(s)	generation facility status and to begin operation on _3/31/20 Miscellaneous section starting on page 19)	
Application Informa	OF status. A floor notice of self-cert section on page 1k What type(s) of O Qualifying sma 1l What is the purpo Original certifi Change(s) to a (identify type	iffication to verify compliance. See to a for more information. F status is the applicant seeking for it also be and expected effective date(s) of cation; facility expected to be installed a previously certified facility to be effective and describe a previously certified facility to be effective and describe and d	ts facility? (check a Qualifying count this filing? ed by3/1/20 ective onchange(s) in the Mange(s)	generation facility status and to begin operation on _3/31/20 Miscellaneous section starting on page 19)	
Application Informa	OF status. A notice notice of self-cert section on page 1k What type(s) of O Qualifying sma 1l What is the purpo Original certifit Change(s) to a (identify type) Name change in Change in Change in	iffication to verify compliance. See to 3 for more information. F status is the applicant seeking for it all power production facility status are and expected effective date(s) of cation; facility expected to be installed a previously certified facility to be effectly of change(s) below, and describe and/or other administrative characteristics.	ts facility? (check a Qualifying count this filing? ed by3/1/20 ective onchange(s) in the Mange(s)	generation facility status and to begin operation on _3/31/20 Miscellaneous section starting on page 19) on capacity and/or cogeneration thermal ou	
Application Informa	OF status. A notice notice of self-cert section on page 1k What type(s) of Q Qualifying sma 1l What is the purpo Original certifit Change(s) to a (identify type) Name change in Change in Change in	iffication to verify compliance. See to 3 for more information. F status is the applicant seeking for it all power production facility status are and expected effective date(s) of cation; facility expected to be installed a previously certified facility to be effectly of change(s) below, and describe ange and/or other administrative change and a previous filing subrements to a previous filing subrements.	ts facility? (check a Qualifying count of this filing? ed by3/1/20 ective onchange(s) in the Mange(s)	generation facility status and to begin operation on _3/31/20 Miscellaneous section starting on page 19) on capacity and/or cogeneration thermal ou	tpı
Application Informa	OF status. A floor notice of self-cert section on page 1k What type(s) of O Qualifying sma 1l What is the purpo Original certifit Change(s) to a (identify type) Name change in Change in Change in Supplement of Supplement	iffication to verify compliance. See to 3 for more information. F status is the applicant seeking for it ill power production facility status ose and expected effective date(s) of cation; facility expected to be installed previously certified facility to be effectly of change(s) below, and describe one and/or other administrative change and/or other administrative change of correction to a previous filing subtraction and content or correction in the Mistage and content or correction	ts facility? (check a Qualifying count this filing? ed by3/1/20 ective onchange(s) in the Mange(s). The power production is power production is power production in the Mange(s) in the Mange(s) expower production is power production is power production is power production in the Mange(s).	generation facility status and to begin operation on _3/31/20 Aiscellaneous section starting on page 19) on capacity and/or cogeneration thermal out on starting on page 19)	tpı
Application Information	OF status. A notice notice of self-cert section on page 1k What type(s) of O Qualifying sma 1l What is the purpo Original certifit Change(s) to a (identify type) Name change in Change in Change in (describe the to the extent The instant	iffication to verify compliance. See to 3 for more information. F status is the applicant seeking for it all power production facility status are and expected effective date(s) of cation; facility expected to be installed a previously certified facility to be effectly of change(s) below, and describe and/or other administrative characteristic plant equipment, fuel use or correction to a previous filing subtraction of the statements is true, characteristic possible, explaining any special circunt facility complies with the Commission in an of the statements is a supplement or correction in an of the statements is a supplement or complies with the Commission in an of the statements in a supplement or complies with the Commission in an of the statements in a supplement or complies with the Commission in an of the statements in a supplement or complies with the Commission in an of the statements in a supplement or complies with the commission in an of the statement of the statements in a supplement or complies with the commission in an of the statement of the stat	ts facility? (check a Qualifying count is filing? ed by3/1/20 ective onchange(s) in the Mange(s) ., power production is cellaneous section eck the box(es) the umstances in the Masion's QF requirement order dated	generation facility status and to begin operation on _3/31/20 Miscellaneous section starting on page 19) on capacity and/or cogeneration thermal ou	tpu fo

Page 6 - All Facilities

FERC	Form	556	2b Telephone number		
12	a Na	me of contact person	713-265-0350		
_	Les	lie A. Freiman	plicant? (check one)		
	Which of the following describes the contact person's relationship to the epiloant the applicant Which of the following describes the contact person's relationship to the epiloant to represent the applicant Applicant (self)				
Contact Information	Lawyer, consultant, or other representative additional Lawyer, consultant Lawye				
Infor	1	2d Company of Organia EDP Renewables North America LLC 2e Street address (if same as Applicant, check here and skip to line 3a)			
ntact	Ze 3		-vinco		
ပိ	2f (City 2g State/pr	Ovince		
	2h	Postal code 2i Country (if not United States)			
		Facility name			
ے		Street address (if a street address does not exist for the facility, check he	ore and skip to line 3c)		
ation and Location	30	Geographic coordinates: If you indicated that no street address exists to then you must specify the latitude and longitude coordinates of the father following formula to convert to decimal degrees from degrees, minutes/60) + (seconds/3600). See the "Geographic Coordegrees + (minutes/60) + (seconds/3600). See the "Geographic Coordegrees + address for your facility in line 3b, then specifying the provided a street address for your facility in line 3b.	For your facility by checking the bo: cility in degrees (to three decimal r nutes and seconds: decimal degree		
+ific		provided a street address to y	de South (-) 42.117 degrees	1	
70	וספו	oR OR	tate/province		
	acilit)	Lakeview 3g Country Country (or check here for independent city)	(if not United States)		
L	Lake Lake				
-		Lake Identify the electric utilities that are contemplated to transact with the fa			
	Utilities	4a Identify utility interconnecting with the facility		_	
	ŧij	4b Identify utilities providing wheeling service or check here if none			
		PacifiCorp (Pacific Power) 4c Identify utilities purchasing the useful electric power output or che	ck here if none 🗌		
	Transacting	4c Identify utilities purchasing the district experimental portland General Electric Company 4d Identify utilities providing supplementary power, backup power, respect bereif none	naintenance power, and/or interruptible power		
	Tran				
		PacifiCorp (Pacific Power)			

ERC Form	556 Hantify all direct owners	of the facility holding at leas	
l pe	rect ownership as of effective date or operation date: Identify all direct owners ercent equity interest. For each identified owner, also (1) indicate whether that ercent equity interest. For each identified owner, also (1) indicate whether that ercent equity interest. For each identified owner, also (1) indicate whether that ercent in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or a holding efficient Science (12 U.S.C. 16451(8)), are companied to the percent equity interest in the facility, then provide the companies with the largest equity interest in the facility.	nd (2) for owners the	20
		Ettle required	If Yes,
d'	irect owners hold at least 10 percent equity interest in the facility. wo direct owners with the largest equity interest in the facility.	Electric utility or holding %	equity
\ tv	wo direct owners with the tary	companyi	nterest
	Full legal names of direct owners	Yes⊠ No □	100%
-	Blue Marmot VII LLC	Yes No	⁹⁶
1)	Bide na	Yes ☐ No ☐ _	96
2)		Yes No .	%
3)		Yes No No	96
4)		Yas□ Nò□	9g
5)		No [90
6)		Yes No	96
7)	Yes No No	
8		45/1 / 100 1 1	
۲ ,		165 11 11 11	
\ \ \ \ \ \ \ \ \ \ \ \ \ \ \ \ \ \ \		ic need	100
odo	Description 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or hold	ility, and (2) are electric utility ding companies, as defined ir	section
and Ope	Check here and continue in the Misses b Upstream (i.e., indirect) ownership as of effective date or operation date: Id of the facility that both (1) hold at least 10 percent equity interest in the facility that both (2) of the Federal Power Act (16 U.S.C. 796(22)), or hold defined in section 3(22) of the Federal Power Act (16 U.S.C. 16451(1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8)))	ility, and (2) are electric utility ding companies, as defined ir	n section tage of iaries of one % equity
wnership and Ope	Check here and continue in the Misses b Upstream (i.e., indirect) ownership as of effective date or operation date: Id of the facility that both (1) hold at least 10 percent equity interest in the facility that both (2) of the Federal Power Act (16 U.S.C. 796(22)), or hold defined in section 3(22) of the Federal Power Act of 2005 (42 U.S.C. 1645) (1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8)) (1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8)) (ility, and (2) are electific utility, ding companies, as defined ir (8)). Also provide the percen tream owners may be subsid	n section tage of iaries of one % equity interest
and Ope	Check here and continue in the Misses b Upstream (i.e., indirect) ownership as of effective date or operation date: Id of the facility that both (1) hold at least 10 percent equity interest in the facility defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or hold 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451) equity interest in the facility held by such owners. (Note that, because upst another, total percent equity interest reported may exceed 100 percent.) Check here if no such upstream owners exist.	cility, and (2) are electific unitary ding companies, as defined in (8)). Also provide the percen stream owners may be subsid	n section tage of iaries of one % equity
wnership and Ope	Check here and continue in the Misses b Upstream (i.e., indirect) ownership as of effective date or operation date: Id of the facility that both (1) hold at least 10 percent equity interest in the facility defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or hold 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451) equity interest in the facility held by such owners. (Note that, because upst another, total percent equity interest reported may exceed 100 percent.) Check here if no such upstream owners exist.	cility, and (2) are electific unitary ding companies, as defined in (8)). Also provide the percen stream owners may be subsid	n section tage of iaries of one % equity interest
wnership and Ope	Description Description of the Federal Power Act (16 U.S.C. 796(22)), or hold defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or hold defined in section 3(22) of the Federal Power Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8)) of the Public Utility Holding Comp	cility, and (2) are electific unitary ding companies, as defined in (8)). Also provide the percen stream owners may be subsid	n section tage of iaries of one % equity interest
wnership and Ope	Description Description of the Federal Power Act (16 U.S.C. 796(22)), or hold defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or hold defined in section 3(22) of the Federal Power Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8))) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8)) of the Public Utility Holding Comp	cility, and (2) are electific unitary ding companies, as defined in (8)). Also provide the percen stream owners may be subsid	n section tage of iaries of one % equity interest
wnership and Ope	Description Description of the Federal Power Act (16 U.S.C. 796(22)), or hold defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or hold defined in section 3(22) of the Federal Power Act (16 U.S.C. 16451(1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8)) of the Pederal Power Act (16 U.S.C. 796(22)), or holding Company Act of 2005 (42 U.S.C. 16451(1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(1262(8)) of the Public Utility Holding Company	cility, and (2) are electific unitary ding companies, as defined in (8)). Also provide the percen stream owners may be subsid	n section tage of iaries of one % equity interest
wnership and Ope	Description (i.e., indirect) ownership as of effective date or operation date: Identify the facility that both (1) hold at least 10 percent equity interest in the facility that facility that both (1) hold at least 10 percent equity interest in the facility defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or hold defined in section 3(22) of the Federal Power Act (16 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company	cility, and (2) are electific unitary ding companies, as defined in (8)). Also provide the percen stream owners may be subsid	n section tage of iaries of one % equity interest
wnership and Ope	Description (i.e., indirect) ownership as of effective date or operation date: Identify that both (1) hold at least 10 percent equity interest in the facility that both (1) hold at least 10 percent equity interest in the facility defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or hold defined in section 3(22) of the Federal Power Act (16 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Pederal Power Act (16 U.S.C. 796(22)), or holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 1262(8) of the Public Utility Holding Company	cility, and (2) are electific unitary ding companies, as defined in (8)). Also provide the percen stream owners may be subsid	n section tage of iaries of one % equity interest
wnership and Ope	Destream (i.e., indirect) ownership as of effective date or operation date: Identify that both (1) hold at least 10 percent equity interest in the facility that both (1) hold at least 10 percent equity interest in the facility of the facility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 1645) (1262(8) o	cility, and (2) are electific unitary ding companies, as defined in (8)). Also provide the percen stream owners may be subsid	n section tage of iaries of one % equity interest
wnership and Ope	 □ Check here and continue in the miscal Light Check here and continue in the miscal of the facility that both (1) hold at least 10 percent equity interest in the facility that both (1) hold at least 10 percent equity interest in the facility defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or hold 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 equity interest in the facility held by such owners. (Note that, because upster another, total percent equity interest reported may exceed 100 percent.) Check here if no such upstream owners exist. □ Full legal names of electric utility or holding company upster another. America LLC 2) 3) 4) 5) 6) 7) 	cility, and (2) are electific unitary ding companies, as defined in (8)). Also provide the percen stream owners may be subsid	n section tage of iaries of one % equity interest
wnership and Ope	 □ Check here and continue in the misce. □ Upstream (i.e., indirect) ownership as of effective date or operation date: Id of the facility that both (1) hold at least 10 percent equity interest in the facility defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or hold 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510 equity interest in the facility held by such owners. (Note that, because upstream owners, total percent equity interest reported may exceed 100 percent.) □ Check here if no such upstream owners exist. □ □ Full legal names of electric utility or holding company upstream owners. 1) EDP Renewables North America LLC 2) 3) 4) 5) 6) 7) 	cility, and (2) are electific unitary ding companies, as defined in (8)). Also provide the percen stream owners may be subsid	n section tage of iaries of one % equity interest
wnership and Ope	Description (i.e., indirect) ownership as of effective date or operation date: Ide of the facility that both (1) hold at least 10 percent equity interest in the facility that both (1) hold at least 10 percent equity interest in the facility defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or hold defined in section 3(22) of the Federal Power Act of 2005 (42 U.S.C. 164510) (1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510) (1962) (cility, and (2) are electric dind ding companies, as defined in (8)). Also provide the percent ream owners may be subsidestream owners	% equity interest
wnership and Ope	Description (i.e., indirect) ownership as of effective date or operation date: Ide of the facility that both (1) hold at least 10 percent equity interest in the facility that both (1) hold at least 10 percent equity interest in the facility defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or hold defined in section 3(22) of the Federal Power Act of 2005 (42 U.S.C. 164510) (1262(8)) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164510) (1962) (cility, and (2) are electric dind ding companies, as defined in (8)). Also provide the percent ream owners may be subsidestream owners	% equity interest
wnership and Ope	 □ Check here and continue in the Miscons b Upstream (i.e., indirect) ownership as of effective date or operation date: Id of the facility that both (1) hold at least 10 percent equity interest in the facility that footh (1) hold at least 10 percent equity interest in the facility defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or hold defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or hold defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or hold 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 164516) another, total percent equity interest reported may exceed 100 percent.) Check here if no such upstream owners exist. □ Full legal names of electric utility or holding company upstream owners are also because the provided and the provided an	cility, and (2) are electric dind ding companies, as defined in (8)). Also provide the percent ream owners may be subsidestream owners	% equity interest

	point(s) of
Indicate the maximum gross and maximum net electric power production capacity of the facility at the delivery by completing the worksheet below. Respond to all items. If any of the parasitic loads and/or lead the completing the worksheet below. Respond to all items. If any of the parasitic loads and/or lead the completing the worksheet below.	losses identified in
Indicate the maximum gross and maximum net electric purificate the purificate the maximum gross and gross and gross and gross and gross and gross and gross	
lines 7b through 7e are negligible, enter zero for those lines.	10,000 kW
7a The maximum gross power production experience of the maximum gross power production	
7b Parasitic station power used at the racincy composed at the racincy compo	
power production processes (for instance, power consumed by the non-power production activities in your	5 kW
t and narasilic station p	102.5 kW
7c Electrical losses in interconnection transformers	10 kW
7d Electrical losses in AC/DC conversion equipment, if any	
7d Electrical losses in AC/DC conversion equipment 7d Electrical losses in AC/DC conversion equipment 7d Electrical losses in power lines or facilities (other than transformers and AC/DC 7d Other interconnection losses in power lines or facilities (other than transformers and AC/DC 7d Other interconnection losses in power lines or facilities (other than transformers and AC/DC 7d Other interconnection losses in power lines or facilities (other than transformers and AC/DC 7d Other interconnection losses in power lines or facilities (other than transformers and AC/DC 7d Other interconnection losses in power lines or facilities (other than transformers and AC/DC 7d Other interconnection losses in power lines or facilities (other than transformers and AC/DC 7d Other interconnection losses in power lines or facilities (other than transformers and AC/DC 7d Other interconnection losses in power lines or facilities (other than transformers and AC/DC 7d Other interconnection losses in power lines or facilities (other than transformers and AC/DC 7d Other interconnection losses in power lines or facilities (other than transformers and AC/DC 7d Other interconnection losses in power lines or facilities (other than transformers and AC/DC 7d Other interconnection losses in power lines or facilities (other than transformers and AC/DC 7d Other interconnection losses in power lines or facilities (other than transformers and AC/DC 7d Other interconnection losses in power lines or facilities (other than transformers and AC/DC 7d Other interconnection losses in power lines or facilities (other than transformers and AC/DC 7d Other interconnection losses in power lines or facilities (other than transformers and AC/DC 7d Other 1d Other	. 41 kW
conversion equipment) between with the utility 7f Total deductions from gross power production capacity = 7b + 7c + 7d + 7e	158.5 kW
7f Total deductions non-group.	9,841.5 kW
7g Maximum net power production capacity = 7a - 7f	fy all boilers, heat

7h Description of facility and primary components: Describe the facility and its operation. Identify all boilers, heat recovery steam generators, prime movers (any mechanical equipment driving an electric generator), electrical generators, photovoltaic solar equipment, fuel cell equipment and/or other primary power generation equipment used in the facility. Descriptions of components should include (as applicable) specifications of the nominal capacities for mechanical output, electrical output, or steam generation of the identified equipment. For each piece of equipment identified, clearly indicate how many pieces of that type of equipment are included in the plant, and which components are normally operating or normally in standby mode. Provide a description of how the components operate as a system. Applicants for cogeneration facilities do not need to describe operations of systems that are clearly depicted on and easily understandable from a cogeneration facility's attached mass and heat balance diagram; however, such applicants should provide any necessary description needed to understand the sequential operation of the facility depicted in their mass and heat balance diagram. If additional space is needed, continue in the Miscellaneous section starting on page 19.

The facility will be a solar PV plant consisting of 38,715 polycrystalline modules of nominal 335W rating each. Total plant rating will be 12.970 MWdc/10MWac. Modules will be mounted to single-axis trackers.

Central inverter stations will be located at intermediate points in the PV field. Modules will be evenly distributed to the inverter stations. The total inverter nameplate rating will be 10.0MWac. Each inverter will be directly coupled to a 34.5kV step-up transformer. The transformers will be connected to a 34.5kV AC collection system, which will feed into the plant switchgear.

The plant switchgear will feed a 34.5kV transmission line, which will run overhead approximately 6.5 miles to the PacifiCorp Mile-Hi Substation.

Inside the Mile-Hi Substation, the transmission line will connect to a new bay containing a facility-owned 34.5kV/115kV GSU transformer, associated breakers, switching, bus, and controls.

The facility-owned components at Mile-Hi substation are considered part of the self-certified qualifying facility.

Information Required for Small Power Production Facility

If you indicated in line 1k that you are seeking qualifying small power production facility status for your facility, then you

nformat	tion	Required	ou are seeking q	ualifying small powe	er production racine,	
If you i	ndicate	ed in line 1k that ?	you are seeming i	ualifying small powe wise, skip page 10. ower production car	pacity of any small power produ er production facilities that use and are located at the same site	uction facility, together
must r						the same energy
	Pursu	ant to 18 C.F.R. §	292.204(a), the pr	any other small pow	er production facilities that use nd are located at the same site ation, or to demonstrate that y seothermal Power Production	, may not exceed 80
	with t	he power produc	Tion capacity and	n(s) or its affiliates, a	nd are located at the same site ation, or to demonstrate that y Geothermal Power Production 1 102-46, 105 Stat. 249 (1991)),	our facility is exempt
	resou	rce, are owned b	y the same pain	ce with this size limit	ration, or to demonstrate that y Geothermal Power Production L. 102-46, 105 Stat. 249 (1991)),	Incentives ACLOI 1990
	mega	watts. To demoi	n under the Solar	r, Wind, Waste, and C	102-46, 105 Stat. 249 (1991)),	, respond to lines ou
	Ifrom	this size infination	- , 2024 (1990)	as amenaea by Fub.	L. • • •	
	1 (Pub	L. 101-3/3/10	(ماما بن			. L-apprating
	thro	igh 8e below (as		Lapperating equipn	nent located within 1 mile of the	5b. or their affiliates, holds
	83	Identify any facili	ties with electrica	for which any of the	entities identified in lines 32 of	
	egu	ipment of the ins	tant facility, and i	Of Willers as 2	nent located within 1 mile of the entities identified in lines 5a or	
	110	act a a nercence	9,			
	Cha	ck here if no such	facilities exist.	\boxtimes		Maximum net power
\	Cire			Root gocker "	Common owner(s)	production capacity
S S	1	Facility	OCALION	(if any)		kW
1:5 5	1	(city or col	unty, state)	OE -		kW
of Compliance Limitations	1)			QF	take and the first and take the property and the state of	KVV
ta	\'`.		AND DESCRIPTION OF THE PROPERTY OF THE PROPERT	QF		kW
10 E	(2)					
19 17	2			QF	ion starting on page 19 if addit	tional space is needed
	(3)			sect	ion starting on page 19 if addit	lional space
Certification with Size	!	Check here a	nd continue in the	e Miscellaneous see	duction Incentives Act of 1990 04(a) for certain facilities that w 18 C.E.R. § 292.204(a) by virtue	(Incentives Act) provides
ati S	2		d Go	othermal Power Pro	duction Incentives Act of the	vere certified prior to 1995.
10 +	8 ت	b The Solar, Wir	d, Waste, and Ge	s in 18 C.F.R. § 292.2	04(a) for certain facilities the	of the Incentives Act!
Cif.	- \e	exemption from t	ne size ilimitation.	ne size limitations in	duction Incentives Act of 1990 04(a) for certain facilities that w 18 C.F.R. § 292.204(a) by virtue No (skip lines 8c thro	ah 8a)
1		Are you seeking e	xemption nom a		No (skip lines 8c thro	ugit 8e)
ΙŬ	1	☐ Yes (con	tinue at line 8c b	elow)	ication for Commission certific	ation of the facility filed on or
			Leatice of self-	certification or appl	ication for Commission 2	
	\	8c Was the origi	nal notice of seri	□ No □		es No
		nd Did construc	tion of the facilit	y commence on or i	pefore December 31, 1999? Y	sed toward the completion of If you answered Yes, provide construction timeline (in
		80 Did corise		indicate whether re	easonable diligence was exclusive	sed toward the compression of the leading of the leading to the leading of the le
		8e If you answe	red No in line ou	Il factors relevant to	easonable diligence was executed construction? Yes \(\sum \) No \(\subseteq tion starting on page 19 of the pafter the facility was certified)	construction timeline (in
		the facility, takir	ig into account a	ne Miscellaneous sec	tion starting on page 19 of the	and the diligence exercised
		la brief narrauve	CAPILL	tion started 50 long	alterare	
		i narriculai, ucac		_		a s to in minimal
		I toward comple	HOLLOLE		and uction facilities may	on of the last on or
		Pursuant to 18	C.F.R. § 292.204(t	o), qualifying sition;	start-up; testing; flame stabiliz	emergencies, directly affecting less. The amount of fossil fuels less facility during the 12-month
\ v	ıts	amounts, for o	nly the following	purposes, igines, ar	nd alleviation or prevention of	emergencies, directly allecting ges. The amount of fossil fuels ne facility during the 12-month alendar year thereafter.
1 2	<u>P</u>					
<u>a</u> .	Ē	the public hea	Ith, safety, or wei	ot exceed 25 percen	t of the total energy input of a	lendar year thereafter.
10	رق آ	Lucad tor IDESC	Duipos	c the first DEC	MILES CICE	
1 8	: : <u>=</u>	period begini	ing with a		with respect to uses of	tossii iuei.
c	Requirements		-f.compliance	with 18 C.F.R. § 292	.204(b) with respect to uses of fossil fuels exclusively for the p	acoc listed above.
	3e	9a Certificati	on of Compilation	معدد النبي عند م	fossil fuels exclusively for the p	urposes listed data
of Compliance	ט ה		cant certifies that	t the facility will use	fossil fuels exclusively for the processil fuels exclusively for the processil fuels exclusively for the processil fuels used at the facility will recessil fuels used at the facility will recession.	stand used annually:
\ 9)				2 204(h) with respect to amoun	nt of fossii ruei used armaery
1:	ertification o ith Fuel Use	at Contificat	ion of complianc	e with 18 C.F.R. 9 29	2.204(b) with respect to amounts sil fuel used at the facility will rescility during the 12-month per	ot, in aggregate, exceed 25
\ \ \	e a	9b Certificat		at the amount of fos	sil fuel used at the facility will r	iod beginning with the date the
\ 6	걸대	App	icant certifies the	nergy input of the fa	icility during the 12-month per	not, in aggregate, exceed 29 iod beginning with the date the
:	E S	⊠ pero	ent of the total e	electric energy or a	ncility during the 12 many calendar year thereafter.	
1	<u>ਜ</u> ਼ ਦ	facil	ity first produces	Ciccuit 2.		

Information Required for Cogeneration Facility If you indicated in line 1k that you are seeking qualifying cogeneration facility status for your facility, then you must respond to the items on pages 11 through 13. Otherwise, skip pages 11 through 13.

Pursene use cyclinhe 29.	suant to 18 C.F.R. § 292.26 rgy (such as heat or stead of energy. Pursuant to 18 le cogeneration facility, the rmal application or process 2,205(a); or (2) for a botto plication or process for p Topping-cycle co To help demonstrate other requirements so balance diagram der meet certain require below to certify that	Otherwise, skip pages 11 through 13. Otherwise, skip pages 11 through 13. Otherwise, skip pages 11 through 13. O2(c), a cogeneration facility produces electric energy and forms of useful thermal m) used for industrial, commercial, heating, or cooling purposes, through the sequential m) used for industrial, commercial, heating, or cooling purposes, through the sequential m) used for industrial, commercial, heating, or cooling purposes, through the sequential m used for industrial, commercial, heating, or cooling purposes, through the sequential is a topping-industrial use of energy means the following: (1) for a topping-is a topping
	Check to certify compliance with	Requirement New durts of all prime movers,
General Cogeneration Information	indicated requirement	Diagram must show orientation within system piping and/or ducts of all prime movers, heat recovery steam generators, boilers, electric generators, and condensers (as applicable), as well as any other primary equipment relevant to the cogeneration process. Any average annual values required to be reported in lines 10b, 12a, 13a, 13b, 13d, 13f, 14a, 15b, 15d and/or 15f must be computed over the anticipated hours of operation. Diagram must specify all fuel inputs by fuel type and average annual rate in Btu/h. Fuel for supplementary firing should be specified separately and clearly labeled. All specifications of fuel inputs should use lower heating values. Diagram must specify average gross electric output in kW or MW for each generator. Diagram must specify average mechanical output (that is, any mechanical energy taken off of the shaft of the prime movers for purposes not directly related to electric power off of the shaft of the prime movers for purposes not directly related to electric power output. At each point for which working fluid flow conditions are required to be specified (see below), such flow condition data must include mass flow rate (in lb/h or kg/s), temperature (in °F, R, °C or K), absolute pressure (in psia or kPa) and enthalpy (in Btu/lb temperature (in °F, R, °C or K), absolute pressure (in psia or kPa) and enthalpy (in Btu/lb temperature (in °F, R, °C or K), absolute pressure flow and specific heat of that liquid are clear point in the cycle) and where the type of liquid and specific heat of that liquid are clear point in the diagram or in the Miscellaneous section starting on page 19, only mas indicated on the diagram or in the Miscellaneous section starting on page 19, only mas indicated on the diagram or in the Miscellaneous section starting on page 19, only mas indicated on the diagram or in the Miscellaneous section starting on page 19, only mas indicated on the diagram or in the Miscellaneous section starting on page 19, only mas indicated on the diagram or in the Miscellaneous sec

	Page 12 - Cogeneration Transmission
,	5.5. (EDA of 2005) established a new section 210(n) of
the	Act 2005 cogeneration facilities: The Energy Policy Act of 2005 (EPAct 2005) established a new section 210(n) of Public Utility Regulatory Policies Act of 1978 (PURPA), 16 USC 824a-3(n), with additional requirements for any alifying cogeneration facility that (1) is seeking to sell electric energy pursuant to section 210 of PURPA and (2) alifying cogeneration facility on August 8, 2005, or had not filed a self-certification or application for as either not a cogeneration facility on August 8, 2005, or had not filed a self-certification or application for as either not a cogeneration of QF status on or before February 1, 2006. These requirements were implemented by the commission certification of QF status on or before February 1, 2006. These requirements were implemented by the commission in 18 C.F.R. § 292.205(d). Complete the lines below, carefully following the instructions, to demonstrate commission in 18 C.F.R. § 292.205(d). Complete the lines below, carefully following the instructions, to demonstrate commission in 18 c.F.R. § 292.205(d). Complete the lines below, carefully following the instructions, to demonstrate commission in 18 c.F.R. § 292.205(d). Complete the lines below, carefully following the instructions, to demonstrate commission in 18 c.F.R. § 292.205(d). The complete the lines below, carefully following the instructions are complete to the commission of the complete the lines below, carefully following the instructions are complete to the complete the lines below, carefully following the instructions are complete to the complete the lines below, carefully following the instructions are complete to the complete to t
\w	Attributed and a sublifying cogeneration facility on or before August 8, 2003: 10 and application
1	In the littles does not be the subject of the little state of the
\ 1 \ f	Was the initial filing seeking certification of your team, 1,2006? Yes No Street No St
F	If the answer to either line 11a or 11b is Yes, then continue of
	11a and 11b die No, skip
se	11a and 11b are No, skip to line 11e below. 11a and 11b are No, skip to line 11e below. 11a and 11b are No, skip to line 11e below. 11c With respect to the design and operation of the facility, have any changes been implemented on output and line in the power of the facility, have any changes been implemented on output and line in the power of the facility, have any changes been implemented on output and line in the power of the facility, have any changes been implemented on output and line in the power of the facility, have any changes been implemented on output and line in the power of the facility, have any changes been implemented on output and line in the power of the facility and line in
	February 2, 2006 that affect general plant operation, and a state of the state of t
tal	February 2, 2006 that affect general plant operation, affects February 2, 2006 that affect general plant's capacity on February 1, 2006? production capacity from the plant's capacity on February 1, 2006?
s Requirements for Fundamental Use Output from Cogeneration Facilities	Yes (continue at line 11d below) No. Your facility is not subject to the requirements of 18 C.F.R. § 292.205(d) at this time. However, it may be No. Your facility is not subject to the requirements of 18 C.F.R. § 292.205(d) at this time. However, it may be No. Your facility is not subject to the requirements of 18 C.F.R. § 292.205(d) at this time. However, it may be No. Your facility is not subject to the requirements of 18 C.F.R. § 292.205(d) at this time. However, it may be
	Yes (continue at line 1782) No. Your facility is not subject to the requirements of 18 C.F.R. § 292.205(d) at this time. However, it may be not subject to the requirements of 18 C.F.R. § 292.205(d) at this time. However, it may be not subject to the requirements in the future if changes are made to the facility. At such time, the applicant subject to to these requirements in the future if changes are made to the facility. Skip lines 11d through 11j.
de tic	No. Your facility is not subject to the requirements in the future if changes are made to the racing. Subject to to these requirements in the future if changes are made to the racing. Skip lines 11d through 11j. Would need to recertify the facility to determine eligibility. Skip lines 11d through 11j. Would need to recertify the facility to determine eligibility. Skip lines 11d through 11j. Would need to recertify the facility to determine eligibility. Skip lines 11d through 11j.
L C	would need to recertify the facility to determine engineers would need to recertify the facility to determine engineers would need to recertify the facility to determine engineers would need to recertify the facility would need to recertify the facility to determine engineers.
II U	subject to to these requirements would need to recertify the facility to determine eligibility. Skip lines 11d divisors would need to recertify the facility to determine eligibility. Skip lines 11d divisors as to make the facility would need to recertify the facility to determine eligibility. Skip lines 11d divisors as to make the facility would need to recertify the facility that the changes identified in line 11c are not so significant as to make the facility and the facility should need to recertify the facility that would be subject to the 18 C.F.R. § 292.205(d) cogeneration requirements? 11d Does the applicant contend that the changes identified in line 11c are not so significant as to make the facility of the facility of the facility should need to recertify the facility that would be subject to the 18 C.F.R. § 292.205(d) cogeneration requirements? 12d Does the applicant contend that the changes identified in line 11c are not so significant as to make the facility of
ge	11d Does the applicant contend that the Changes had be subject to the 18 C.F.R. § 292.205(d) cogeneration required to the 200 cogenerati
Sign	Ves Provide in the Miscellaneous section starting on page. Yes Provide in the Miscellaneous section starting on page. 110 through 11i.
l ci	a "new" cogeneration facility that would be by Yes. Provide in the Miscellaneous section starting on page 19 a description of any relevant changes Yes. Provide in the Miscellaneous section starting on page 19 a description of any relevant changes Yes. Provide in the Miscellaneous section starting on page 19 a description of any relevant changes Yes. Provide in the Miscellaneous section starting on page 19 a description of any relevant changes Yes. Provide in the Miscellaneous section starting on page 19 a description of any relevant changes Yes. Provide in the Miscellaneous section starting on page 19 a description of any relevant changes Yes. Provide in the Miscellaneous section starting on page 19 a description of any relevant changes Yes. Provide in the Miscellaneous section starting on page 19 a description of any relevant changes Yes. Provide in the Miscellaneous section starting on page 19 a description of any relevant changes Yes. Provide in the Miscellaneous section starting on page 19 a description of any relevant changes Yes. Provide in the Miscellaneous section starting on page 19 a description of any relevant changes Yes. Provide in the Miscellaneous section starting on page 19 a description of any relevant changes Yes. Provide in the Miscellaneous section starting on page 19 a description of any relevant changes Yes. Provide in the Miscellaneous section starting on page 19 a description of any relevant changes Yes. Provide in the Miscellaneous section starting on page 19 a description of any relevant changes Yes. Provide in the Miscellaneous section starting on page 19 a description of any relevant changes Yes. Provide in the Miscellaneous section starting on page 19 a description of why the facility should not be Yes. Provide in the Miscellaneous section starting on page 19 a description of why the facility should not be Yes. Provide in the Miscellaneous section starting on page 19 a description of why the facility should not be Yes. Provide in the Miscellaneous section startin
or Or	Yes. Provide in the Miscellaneous section status and a discussion of why the facility should be section status and a discussion of why the facility should be section as the facility (including the purpose of the changes) and a discussion of why the facility should be the facility (including the purpose of the facility in light of these changes. Skip lines 11e through 11j. On Applicant stipulates to the fact that it is a "new" cogeneration facility (for purposes of determining the No. Applicant stipulates to the fact that it is a "new" cogeneration facility (for purposes of determining the No. Applicant stipulates to the fact that it is a "new" cogeneration facility (for purposes of determining the No. Applicant stipulates to the fact that it is a "new" cogeneration facility (for purposes of determining the No. Applicant stipulates to the fact that it is a "new" cogeneration facility (for purposes of determining the No. Applicant stipulates to the fact that it is a "new" cogeneration facility (for purposes of determining the No. Applicant stipulates to the fact that it is a "new" cogeneration facility (for purposes of determining the No. Applicant stipulates to the fact that it is a "new" cogeneration facility (for purposes of determining the No. Applicant stipulates to the fact that it is a "new" cogeneration facility (for purposes of determining the No. Applicant stipulates to the fact that it is a "new" cogeneration facility (for purposes of determining the No. Applicant stipulates to the fact that it is a "new" cogeneration facility (for purposes of determining the No. Applicant stipulates to the fact that it is a "new" cogeneration facility (for purposes of determining the No. Applicant stipulates to the fact that it is a "new" cogeneration facility (for purposes of determining the No. Applicant stipulates the fact that it is a "new" cogeneration facility (for purposes of determining the No. Applicant stipulates the No. Applicant stipulates (for purpose) (for purpose) (for purpose) (for purpose) (for purpo
e f	No. Applicant stipulates to the fact that it is a "new" cogeneration facility (for purposes of determining the No. Applicant stipulates to the fact that it is a "new" cogeneration facility (for purposes of determining the No. Applicant stipulates to the fact that it is a "new" cogeneration facility (for purposes of determining the No. Applicant stipulates to the fact that it is a "new" cogeneration facility (for purposes of determining the No. Applicant stipulates to the fact that it is a "new" cogeneration facility (for purposes of determining the No. Applicant stipulates to the fact that it is a "new" cogeneration facility (for purposes of determining the No. Applicant stipulates to the fact that it is a "new" cogeneration facility (for purposes of determining the No. Applicant stipulates to the fact that it is a "new" cogeneration facility (for purposes of determining the No. Applicant stipulates to the fact that it is a "new" cogeneration facility (for purposes of determining the No. Applicant stipulates to the fact that it is a "new" cogeneration facility (for purposes of determining the No. Applicant stipulates to the fact that it is a "new" cogeneration facility (for purposes of determining the No. Applicant stipulates to the fact that it is a "new" cogeneration facility (for purposes of determining the No. Applicant stipulates to the fact that it is a "new" cogeneration facility (for purposes of determining the No. Applicant stipulates to the fact that it is a "new" cogeneration facility (for purposes of determining the No. Applicant stipulates to the fact that it is a "new" cogeneration facility (for purposes of determining the No. Applicant stipulates to the fact that it is a "new" cogeneration facility (for purposes of determining the No. Applicant stipulates the No. Appli
= ±	applicability of the requirements of 18 C.F.R. 9 292.205(e); applicability of 18 C.F.R. 9 292.205(e); applicab
합합	initiated on or after February 2, 2006. Continue section 210 of PURPA?
	initiated on or after February 2, 2003. 11e Will electric energy from the facility be sold pursuant to section 210 of PURPA? Yes. The facility is an EPAct 2005 cogeneration facility. You must demonstrate compliance with 18 C.F.R. § Yes. The facility is an EPAct 2005 cogeneration facility. You must demonstrate compliance with 18 C.F.R. §
(4)	The state of the s
0 5	Yes. The facility is an CFACE 2002 Yes. The facilit
t 2	Yes. The facility is an EPAct 2003 cogche and the 11f below. 292.205(d)(2) by continuing at line 11f below. No. Applicant certifies that energy will <i>not</i> be sold pursuant to section 210 of PURPA. Applicant also certifies have requirements of its understanding that it must recertify its facility in order to determine compliance with the requirements of its understanding that it must recertify its facility in order to determine compliance with the requirements of its understanding that it must recertify its facility in order to determine compliance with the requirements of its understanding that it must recertify its facility in order to determine compliance with the requirements of its understanding that it must recertify its facility in order to determine compliance with the requirements of its understanding that it must recertify its facility in order to determine compliance with the requirements of its understanding that it must recertify its facility in order to determine compliance with the requirements of its understanding that it must recertify its facility in order to determine compliance with the requirements of its understanding that it must recertify its facility in order to determine compliance with the requirements of its understanding that it must recertify its facility in order to determine compliance with the requirements of its understanding that it must recertify its facility in order to determine compliance with the requirements of its understanding that it is understanding t
EPAct 200 of Energy	No. Applicant certifies that experience the surface of the surface
G. fo	No. Applicant certifies that energy will not be said personal pers
	through 11j. through 11j.
	through 11j. 11f Is the net power production capacity of your cogeneration facility, as indicated in line 7g above, less than or
	11f Is the net power production capacity of your cogenerous equal to 5,000 kW. 18 C.F.R. § 292.205(d)(4) provides a equal to 5,000 kW? Yes, the net power production capacity is less than or equal to 5,000 kW and smaller capacity comply with the yes, the net power production facilities of 5,000 kW and smaller capacity comply with the yes, the next power production facilities of 5,000 kW and smaller capacity comply with the
	equal to 5,000 kW? equal to 5,000 kW? equal to 5,000 kW. 18 C.F.R. § 292,205 kW. the pet power production capacity is less than or equal to 5,000 kW and smaller capacity comply with the
	1 1- 14- NIA DIPSUMPRION
	Yes, the net power production capacity is less than of 5,000 kW and smaller capacity comply with the rebuttable presumption that cogeneration facilities of 5,000 kW and smaller capacity comply with the rebuttable presumption that cogeneration facilities of 5,000 kW and smaller capacity comply with the rebuttable presumption that cogeneration facilities of 5,000 kW and smaller capacity comply with the rebuttable presumption that cogeneration facilities of 5,000 kW and smaller capacity comply with the
	certifies its understanding that, should display the recertified to (among other things) demonstrate compliance
	kW, then the lacinty made at a through 11i
	292.205(d)(2). Skip lines 3.3
	kW, then the facility must be reasonable to the facility must be reasonable to the second sec
	requirements to fundament
1	the next page at line 11g.

Lines 11g through 11k below guide the applicant through the process of demonstrating compliance with the requirements for "fundamental use" of the facility's energy output. 18 C.F.R. § 292.205(d)(2). Only respond to the lines on this page if the instructions on the previous page direct you to do so. Otherwise, skip this page.

18 C.F.R. § 292.205(d)(2) requires that the electrical, thermal, chemical and mechanical output of an EPAct 2005 cogeneration facility is used fundamentally for industrial, commercial, residential or institutional purposes and is not intended fundamentally for sale to an electric utility, taking into account technological, efficiency, economic, and variable thermal energy requirements, as well as state laws applicable to sales of electric energy from a qualifying facility to its host facility. If you were directed on the previous page to respond to the items on this page, then your facility is an EPAct 2005 cogeneration facility that is subject to this "fundamental use" requirement.

The Commission's regulations provide a two-pronged approach to demonstrating compliance with the requirements for fundamental use of the facility's energy output. First, the Commission has established in 18 C.F.R. § 292.205(d)(3) a "fundamental use test" that can be used to demonstrate compliance with 18 C.F.R. § 292.205(d)(2). Under the fundamental use test, a facility is considered to comply with 18 C.F.R. § 292.205(d)(2) if at least 50 percent of the facility's total annual energy output (including electrical, thermal, chemical and mechanical energy output) is used for industrial, commercial, residential or institutional purposes.

Second, an applicant for a facility that does not pass the fundamental use test may provide a narrative explanation of and support for its contention that the facility nonetheless meets the requirement that the electrical, thermal, chemical and mechanical output of an EPAct 2005 cogeneration facility is used fundamentally for industrial, commercial, residential or institutional purposes and is not intended fundamentally for sale to an electric utility, taking into account technological, efficiency, economic, and variable thermal energy requirements, as well as state laws applicable to sales of electric energy from a qualifying facility to its host facility.

Complete lines 11g through 11j below to determine compliance with the fundamental use test in 18 C.F.R. § 292.205(d)(3). Complete lines 11g through 11j even if you do not intend to rely upon the fundamental use test to demonstrate compliance with 18 C.F.R. § 292.205(d)(2).

- 11g Amount of electrical, thermal, chemical and mechanical energy output (net of internal generation plant losses and parasitic loads) expected to be used annually for industrial, MWh commercial, residential or institutional purposes and not sold to an electric utility 11h Total amount of electrical, thermal, chemical and mechanical energy expected to be MWh 11i Percentage of total annual energy output expected to be used for industrial, commercial, residential or institutional purposes and not sold to a utility 0 %
- = 100 * 11g /(11g + 11h) 11j Is the response in line 11i greater than or equal to 50 percent?

Yes. Your facility complies with 18 C.F.R. § 292.205(d)(2) by virtue of passing the fundamental use test provided in 18 C.F.R. § 292.205(d)(3). Applicant certifies its understanding that, if it is to rely upon passing the fundamental use test as a basis for complying with 18 C.F.R. § 292.205(d)(2), then the facility must comply with the fundamental use test both in the 12-month period beginning with the date the facility first produces electric energy, and in all subsequent calendar years.

No. Your facility does not pass the fundamental use test. Instead, you must provide in the Miscellaneous section starting on page 19 a narrative explanation of and support for why your facility meets the requirement that the electrical, thermal, chemical and mechanical output of an EPAct 2005 cogeneration facility is used fundamentally for industrial, commercial, residential or institutional purposes and is not intended fundamentally for sale to an electric utility, taking into account technological, efficiency, economic, and variable thermal energy requirements, as well as state laws applicable to sales of electric energy from a QF to its host facility. Applicants providing a narrative explanation of why their facility should be found to comply with 18 C.F.R. § 292.205(d)(2) in spite of non-compliance with the fundamental use test may want to review paragraphs 47 through 61 of Order No. 671 (accessible from the Commission's QF website at www.ferc.gov/QF), which provide discussion of the facts and circumstances that may support their explanation. Applicant should also note that the percentage reported above will establish the standard that that facility must comply with, both for the 12-month period beginning with the date the facility first produces electric energy, and in all subsequent calendar years. See Order No. 671 at paragraph 51. As such, the applicant should make sure that it reports appropriate values on lines 11g and 11h above to serve as the

relevant annual standard, taking into account expected variations in production conditions.

Usefulness of Topping-Cycle Thermal Output

FERC FORM 550		- Lacility
	- Cycle	a Cadenerallolli aciiiy
- d fo	v Tannınd-UVCI	e Cogcheration
or partice Reguliced to	il lobbing cha.	- Jamalagy
Information Required fo		cla cogeneration technology

If you indicated in line 10a that your facility represents topping-cycle cogeneration technology, then you must respond to the items on pages 14 and 15. Otherwise, skip pages 14 and 15.

The thermal energy output of a topping-cycle cogeneration facility is the net energy made available to an industrial or commercial process or used in a heating or cooling application. Pursuant to sections 292.202(c), (d) and (h) of the Commission's regulations (18 C.F.R. §§ 292.202(c), (d) and (h)), the thermal energy output of a qualifying toppingcycle cogeneration facility must be useful. In connection with this requirement, describe the thermal output of the topping-cycle cogeneration facility by responding to lines 12a and 12b below.

12a Identify and describe each thermal host, and specify the annual average rate of thermal output made available to each host for each use. For hosts with multiple uses of thermal output, provide the data for each use in Average annual rate of thermal output separate rows.

	Name of entity (thermal host)	Thermal host's relationship to facility; Thermal host's use of thermal output	attributable to use (net of heat contained in process return or make-up water)
	taking thermal output	Select thermal host's relationship to facility	
1)		Select thermal host's use of thermal output	Btu/h
		Select thermal host's relationship to facility	0. 4-
2)		Select thermal host's use of thermal output	Btu/h
		Select thermal host's relationship to facility	Btu/h
3)		Select thermal host's use of thermal output	Btu/n
-		Select thermal host's relationship to facility	Btu/h
4)		Select thermal host's use of thermal output	Btu/II
-		Select thermal host's relationship to facility	Btu/h
5)		Select thermal host's use of thermal output	Brayıı
-		Select thermal host's relationship to facility	Btu/h
6)		of thormal output	
-	Check here and continue	Select thermal host's use of thermal output in the Miscellaneous section starting on page 19 if	additional space is needed
- 1	LJ 6.13	to the At a minimum, provide a brief	description of each use of the

12b Demonstration of usefulness of thermal output: At a minimum, provide a brief description of each use of the thermal output identified above. In some cases, this brief description is sufficient to demonstrate usefulness. However, if your facility's use of thermal output is not common, and/or if the usefulness of such thermal output is not reasonably clear, then you must provide additional details as necessary to demonstrate usefulness. Your application may be rejected and/or additional information may be required if an insufficient showing of usefulness is made. (Exception: If you have previously received a Commission certification approving a specific use of thermal output related to the instant facility, then you need only provide a brief description of that use and a reference by date and docket number to the order certifying your facility with the indicated use. Such exemption may not be used if any change creates a material deviation from the previously authorized use.) If additional space is needed,

continue in the Miscellaneous section starting on page 19.

	" as with the topping-	
n	pplicants for facilities representing topping-cycle technology must demonstrate compliance with the topping-cycle policants for facilities representing topping-cycle technology must demonstrate compliance with the topping-cycle policants for facilities representing topping-cycle and, if applicable, efficiency standard. Section 292.205(a)(1) of the Commission's representation facilities:	
C: re t' () i	egulations (18 C.F.R. § 292.205(a)(1)) establishes the operation of the total energy output. Sections (18 C.F.R. § 292.205(a)(1)) establishes the oless than 5 percent of the total energy output. Section facilities for which the useful thermal energy output must be no less than 5 percent for topping-cycle cogeneration facilities for which 18 C.F.R. § 292.205(a)(2)) establishes the efficiency standard power output of the facility plus one-half the useful 18 C.F.R. § 292.205(a)(2)) establishes the efficiency of the useful power output of the facility plus one-half the useful to the installation commenced on or after March 13, 1980: the useful power output of the total energy input of the total energy output of the facility, thermal energy output is less than 15 percent of the total energy output is less than 15 percent of the total energy output of natural gas and oil to the facility. To demonstrate facility; and (B) if the useful thermal energy input of natural gas and oil to the facility. To demonstrate that your facility is be no less than 45 percent of the total energy input of natural gas and oil to the facility. To demonstrate that your facility is be no less than 45 percent of the total energy input of natural gas and oil to the facility. To demonstrate that your facility is be no less than 45 percent of the total energy input of natural gas and oil to the facility.	
١	exempt from the emelose. 13I below. Calling represents both topping-cycle and bottoming-cycle cogeneration.	
	to-also clear	

If you indicated in line 10a that your facility represents both topping-cycle and bottoming-cycle cogeneration technology, then respond to lines 13a through 13l below considering only the energy inputs and outputs attributable to the topping-cycle portion of your facility. Your mass and heat balance diagram must make clear which mass and energy flow values and system components are for which portion (topping or bottoming) of the cogeneration system.

the to the topping-cycle portion of your components are for which portion to	
attributable to the topping-cycle portion of year components are for which portion to which mass and energy flow values and system components are for which portion which mass and energy flow values and system components are for which portion to which which mass and energy flow values and system components are for which portion to which the components are for which portion to which portion to the components are for which portion to which the components are for which portion to which the components are for which portion to the components are for which the components are components are components.	
which mass and cristian system	Btu/h
which mass and energy flow values are sy cogeneration system. 13a Indicate the annual average rate of useful thermal energy output made availab 1 not of any heat contained in condensate return or make-up water	
13a Indicate the annual average contained in condensate return of mental average contained average c	kW \
cogeneration system. 13a Indicate the annual average rate of useful thermal energy output	With the same of t
13h Indicate the annual average	St. /h
13c Multiply line 13b by 3,412 to convert from kW to Btu/h	0 Btu/h
- Multiply line 13b by 3,412 to convert from KV	CC CC
13c Multiply in a language output taken directly of	DII
the applied average rate of mechanical energy of the power production	n hp
13c Multiply line 13b by 3,412 to converted 13d Indicate the annual average rate of mechanical energy output taken directly of the shaft of a prime mover for purposes not directly related to power production of the shaft of a prime mover for purposes not directly related to power production.	
Lof the shall of a prime	O Btu/h
(this value is usually zero) 13e Multiply line 13d by 2,544 to convert from hp to Btu/h	() Btu/ii
Georgy input from natural gas and oil	Btu/h
13e Multiply line 13d by 2,5 ft. 13f Indicate the annual average rate of energy input from natural gas and oil	
13f Indicate the different state of the last sta	0 %
do operating value = 100 * 13a / (13a + 13c + 13c)	
13g Topping-cycle operating	0 %
	0 70
13g Topping-cycle operators 13h Topping-cycle efficiency value = 100 * (0.5*13a + 13c + 13e) / 13f 13h Topping-cycle efficiency value = 100 * (0.5*13a + 13c + 13e) / 13f 13i Compliance with operating standard: Is the operating value shown in line 1	aggreater than or equal to 5%!
Listhe operating value shown in line i	. Jord)
a Grandiance with operating standard: 15 the operating	nply with operating standard)
13i Compliance with the standard No (does not con	
Yes (complies with operating standard) No (does need a need on or after Mare)	ch 13 1980?
Yes (complies with operating standard) 13j Did installation of the facility in its current form commence on or after Marchael Did installation of the facility in its current form commence on or after Marchael Did installation of the facility in its current form commence on or after Marchael Did installation of the facility in its current form commence on or after Marchael Did installation of the facility in its current form commence on or after Marchael Did installation of the facility in its current form commence on or after Marchael Did installation of the facility in its current form commence on or after Marchael Did installation of the facility in its current form commence on or after Marchael Did installation of the facility in its current form commence on or after Marchael Did installation of the facility in its current form commence on or after Marchael Did installation of the facility in its current form commence on or after Marchael Did installation of the facility in its current form commence on or after Marchael Did installation of the facility in its current form commence on or after Marchael Did installation of the facility in its current form commence on or after Marchael Did installation of the facility in its current form commence on or after Marchael Did installation of the facility in its current form commence or after the facility of the facility in its current form commence or after the facility of the facilit	tunto
13j Did installation of the facility in its current form commence on or after many distribution. Yes. Your facility is subject to the efficiency requirements of 18 C.F.R. § Yes. Your facility the efficiency requirement by responding to line 13k	292.205(a)(2). Demonstrate
Yes. Your facility is subject to the efficiency requirements of 18 C.F.R. § Compliance with the efficiency requirement by responding to line 13k	or 13l, as applicable, below.
Yes. Your facility is subject to the our	
compliance with the efficiency required	and 13l.
t from the efficiency standard. Skip lines 15.	- loss
compliance with the efficiency requirements. Skip lines 13k No. Your facility is exempt from the efficiency standard. Skip lines 13k 13k Compliance with efficiency standard (for low operating value): If the operation of the efficiency value shown in line 13h 150 then indicate below whether the efficiency value shown in line 13h	orating value shown in line 13g is less
13k Compliance with efficiency standard (for low operating value): If the operating value shown in line 13h than 15%, then indicate below whether the efficiency value shown in line 13h than 15%, then indicate below whether the efficiency value shown in line 13h	greater than or equal to 45%:
Compliance with efficiency standard from the conficiency value shown in line 131	(Jard)
1506 then indicate below whether the efficiency	omply with efficiency standard)
than 15%, then we work that the No (does not e	ione /
Yes (complies with efficiency standard) No (does not expected by the first of the operation of the operatio	porating value shown in line 13g is
lead (for high operating value): If the operating value is if the operating value is if the operating value is in the operation of the operati	up shown in line 13h is greater than or
Compliance with efficiency standard from whether the efficiency val	ue snown.
than or equal to 15%, then indicate below the	(dord)
Tyes (complies with efficiency standard (for high operating value): If the operating value of the operation of the standard (for high operating value): If	comply with efficiency standard)
equal to 42.5%: No (does not	
Yes (complies with efficiency standard)	

Information Required for Bottoming-Cycle Cogeneration Facility

If you indi to the iter	cated ns on The th which the Co cycle	ermal energy output of a bottom at least some of the reject heat is ommission's regulations (18 C.F.R. cogeneration facility must be use	pages 16 and 17. ing-cycle cogeneration facility is the energy relate then used for power production. Pursuant to sec \$ 292.202(c) and (e)), the thermal energy output ful. In connection with this requirement, describe for power production by responding to lines 14a	of a qualifying bottoming- of a qualifying bottoming- ethe process(es) from which and 14b below.
	14a	host. For hosts with multiple bot separate rows. Name of entity (thermal host) performing the process from which at least some of the reject heat is used for power production	Thermal host's relationship to facility; Thermal host's process type	the thermal host been augmented for purposes of increasing power production capacity? (if Yes, describe on p. 19)
	1)	preess	Select thermal host's relationship to facility Select thermal host's process type	Yes No
Cycle	2)		Select thermal host's relationship to facility Select thermal host's process type Select thermal host's relationship to facility Select thermal host's process type	Yes No No
Usefulness of Bottoming-Cycle Thermal Output		4b Demonstration of usefulness of dentified above. In some cases, the acility's process is not common, are not provide additional details as additional information may be required a Commission	the Miscellaneous section starting on page 19 if a of thermal output: At a minimum, provide a brieful brief description is sufficient to demonstrate us and/or if the usefulness of such thermal output is necessary to demonstrate usefulness. Your appliquired if an insufficient showing of usefulness is made a certification approving a specific bottoming-cycle a brief description of that process and a referency with the indicated process. Such exemption man made.) If additional space is needed, continue in	ot reasonably clear, then you cation may be rejected and/or ade. (Exception: If you have e process related to the instant ice by date and docket number

No (does not comply with efficiency standard)

than or equal to 45%:

Yes (complies with efficiency standard)

	Page 17 - Bottoming-Cycle	Cogeneration	
orm	556 grade technology and for which installation	commenced on or alter	
th c c s	pplicants for facilities representing bottoming-cycle technology and for which installation pplicants for facilities representing bottoming-cycle technology and for which installation parch 13, 1990 must demonstrate compliance with the bottoming-cycle efficiency standard for the Commission's regulations (18 C.F.R. § 292.205(b)) establishes the efficiency standard for orgeneration facilities: the useful power output of the facility must be no less than 45 percentages and oil for supplementary firing. To demonstrate compliance with the bottomitation (if applicable), or to demonstrate that your facility is exempt from this standard be attandard (if applicable), or to demonstrate that your facility is exempt from this standard be attandard of the facility began, respond to lines 15a through 15h below. Installation of the facility began, respond to lines 15h below considering only the energy input technology, then respond to lines 15a through 15h below considering only the energy input technology, then respond to lines 15a through 15h below considering only the energy input technology, then respond to lines 15a through 15h below considering only the energy input technology.	ning-cycle efficiency sed on the date that cycle cogeneration uts and outputs	
: \	(topping or bottoming).	0?	
במורחומיוס	(topping or bottoming). 15a Did installation of the facility in its current form commence on or after March 13, 198 Yes. Your facility is subject to the efficiency requirement of 18 C.F.R. § 292.205(b) with the efficiency requirement by responding to lines 15b through 15h below. No. Your facility is exempt from the efficiency standard. Skip the rest of page 17	•	
n L	No. Tour rate of net electrical energy output	kW	art.
ار م	15b Indicate the annual average rate of net electrical energy output	0 Btu/h	
$\stackrel{\frown}{>}$	15c Multiply line 15b by 3,412 to convert from kW to Btu/h	0 Btu/11	
Efficiency Value	15d Indicate the annual average rate of mechanical energy output taken on the shaft of a prime mover for purposes not directly related to power production	hp	Ų.
ш	(this value is usually zero) 15e Multiply line 15d by 2,544 to convert from hp to Btu/h	₀ Btu/h	-
	15e Multiply line 15d by 2,344 to com 15f Indicate the annual average rate of supplementary energy input from natural gas	Btu/h	عاليان
	lor oil 100 * (15c + 15e) / 15l	0 %	
	Campliance with efficiency standard: Indicate below whether the efficiency standard:	ie shown in line 15g is greater	
	ar or or all to 45%;	with efficiency started/	1

Certificate of Completeness, Accuracy and Authority

Applicant must certify compliance with and understanding of filing requirements by checking next to each item below and signing at the bottom of this section. Forms with incomplete Certificates of Completeness, Accuracy and Authority will be rejected by the Secretary of the Commission.

rejected by the Secretary of the Commission.	Landicable subitems)
rejected by the Secretary of the Commission. Signer identified below certifies the following: (check all items as He or she has read the filling, including any information cont	nd applicable sales documents, such as cogeneration
Signer identified below certifies the following: (Creckum real filters) He or she has read the filing, including any information contemporary mass and heat balance diagrams, and any information contemporary is contents.	tained in any attached documents, and tained in any attached documents and tained in any attached documents.
He or she has read the filing, including any information cont	tained in the Miscellane
mass and heat balance diagrams, and any	
knows its contents.	ertification, and the provided information is the
Ho or she has provided all of the required information to	
mass and heat balance diagrams, and any information mass and heat balance diagrams, and any information for contents. He or she has provided all of the required information for contents to the best of his or her knowledge and belief.	required by Rule 2005(a)(3) of the Commission's Rules of
reas full power and authority to sign the filin	g; as required by the sign one of the following: (check one)
He or she possess full power and procedure (18 C.F.R. § 385.2005(a)(3)), he or s	g; as required by Rule 2005(a)(3) of the Commission's Rules of the is one of the following: (check one)
Practice and Procedure (
The person on whose behalf the massociation. Of	other organized group on behalf of which the
M An officer of the corporation, trust, association,	other organized group on behalf of which the filing is made authority, agency, or instrumentality on behalf of which the
An officer agent, or employe of the government	n authority) - 5
1 1 cling is made	under BIIIe Ziti of the
A representative qualified to practice before the Practice and Procedure (18 C.F.R. § 385.2101) and	Commission under Rule 2101 of the Commission's Rules of d who possesses authority to sign
Practice and Procedure (18 C.F.R. § 385.2101) and	who per analogs otherwise noted in the
r reactions and ag	grees with their results, unless other the
He or she has reviewed all automatic calculations.	the facility Will
A representative quantical to proceed the Practice and Procedure (18 C.F.R. § 385.2101) and Procedure (18 C.F.R. § 385.210	attachments to the utilities with which the states in which the
He or she has reviewed all automated. Miscellaneous section starting on page 19. He or she has provided a copy of this Form 556 and all a copy of this Form 556 and a copy o	attachments to the utilities with which the facility will well as to the regulatory authorities of the states in which the ice to Public Utilities and State Regulatory Authorities section on
interconnect and transact (see lines 4a through Noti	ice to Public Utilities and State Regulary
page 3 for more information.	p. 1- 2005(c) of the Commission's Rules of Practice and

Provide your signature, address and signature date below. Rule 2005(c) of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2005(c)) provides that persons filing their documents electronically may use typed characters representing his or her name to sign the filed documents. A person filing this document electronically should sign (by typing his or her name) in the space provided below. Date

Your Signature	Your address 808 Travis Street #700	12/21/2016
Leslie A. Freiman	Houston, TX 77002	,
Audit Notes		
o. «Uso Only		
Commission Staff Use Only		

Page 19 - All Facilities

FERC Form 556

Use this space to provide any information for which there was not sufficient space in the previous sections of the form to provide. For each such item of information clearly identify the line number that the information belongs to. You may also use Miscellaneous this space to provide any additional information you believe is relevant to the certification of your facility.

Your response below is not limited to one page. Additional page(s) will automatically be inserted into this form if the length of your response exceeds the space on this page. Use as many pages as you require.

EXHIBIT C START-UP TESTING

VISUAL AND MECHANICAL INSPECTIONS

INVERTER COMMISSIONING

ELECTRICAL OPERATION TESTS

SYSTEM MONITORING VERIFICATION

TRACKER VERIFICATION

INFRARED SCANS

BLOCK TESTING

72-HOUR FUNCTIONAL TEST

GRID MATCH TEST

POWER CHARACTERIZATION

REVENUE METER VERIFICATION

REACTIVE POWER TEST

POWER OUTPUT TEST - PLANT PERFORMANCE AND ACCEPTANCE

EXHIBIT D SCHEDULE

SCHEDULE 201 QUALIFYING FACILITY 10 MW or LESS AVOIDED COST POWER PURCHASE INFORMATION

To provide information about Standard Avoided Costs and Renewable Avoided Costs, Standard Power Purchase Agreements (PPA) and Negotiated PPAs, power purchase prices and price options for power delivered by a Qualifying Facility (QF) to the Company with nameplate capacity of 10,000 kW (10MW) or less.

To owners of QFs making sales of electricity to the Company in the State of Oregon (Seller).

For power purchased from small power production or cogeneration facilities that are QFs as defined in 18 Code of Federal Regulations (CFR) Section 292, that meet the eligibility requirements described herein and where the energy is delivered to the Company's system and made available for Company purchase pursuant to a Standard PPA.

ESTABLISHING CREDITWORTHINESS

The Seller must establish creditworthiness prior to service under this schedule. For a Standard PPA, a Seller may establish creditworthiness with a written acknowledgment that it is current on all existing debt obligations and that it was not a debtor in a bankruptcy proceeding within the preceding 24 months. If the Seller is not able to establish creditworthiness, the Seller must provide security deemed sufficient by the Company as set forth in the Standard PPA.

POWER PURCHASE INFORMATION

A Seller may call the Power Production Coordinator at (503) 464-8000 to obtain more information about being a Seller or how to apply for service under this schedule.

In accordance with terms set forth in this schedule and the Commission's Rules as applicable, the PPA Company will purchase any Energy in excess of station service (power necessary to produce generation) and amounts attributable to conversion losses, which are made available from the Seller.

A Seller must execute a PPA with the Company prior to delivery of power to the Company. The agreement will have a term of up to 20 years as selected by the QF.

A QF with a nameplate capacity rating of 10 MW or less as defined herein may elect the option of a Standard PPA.

PPA (Continued)

Any Seller may elect to negotiate a PPA with the Company. Such negotiation will comply with the requirements of the Federal Energy Regulatory Commission (FERC), and the Commission including the guidelines in Order No. 07-360, and Schedule 202. Negotiations for power purchase pricing will be based on either the filed Standard Avoided Costs or Renewable Avoided Costs in effect at that time.

STANDARD PPA (Nameplate capacity of 10 MW or less)

A Seller choosing a Standard PPA will complete all informational and price option selection requirements in the applicable Standard PPA and submit the executed Agreement to the Company prior to service under this schedule. The Standard PPA is available at www.portlandgeneral.com. . The available Standard PPAs are:

- Standard In-System Non-Variable Power Purchase Agreement
- Standard Off-System Non-Variable Power Purchase Agreement
- Standard In-System Variable Power Purchase Agreement
- Standard Off-System Variable Power Purchase Agreement
- Standard Renewable In-System Non-Variable Power Purchase Agreement
- Standard Renewable Off-System Non-Variable Power Purchase Agreement
- Standard Renewable In-System Variable Power Purchase Agreement
- Standard Renewable Off-System Variable Power Purchase Agreement

The Standard PPAs applicable to variable resources are available only to QFs utilizing wind, solar or run of river hydro as the primary motive force.

GUIDELINES FOR 10 MW OR LESS FACILITIES ELECTING STANDARD PPA

To execute the Standard PPA the Seller must complete all of the general project information requested in the applicable Standard PPA.

When all information required in the Standard PPA has been received in writing from the Seller, the Company will respond within 15 business days with a draft Standard PPA.

The Seller may request in writing that the Company prepare a final draft Standard PPA. The Company will respond to this request within 15 business days. In connection with such request, the QF must provide the Company with any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft Standard PPA.

When both parties are in full agreement as to all terms and conditions of the draft Standard PPA, the Company will prepare and forward to the Seller a final executable version of the agreement within 15 business days. Following the Company's execution, an executed copy will be returned to the Seller. Prices and other terms and conditions in the PPA will not be final and binding until the Standard PPA has been executed by both parties.

OFF-SYSTEM PPA

A Seller with a facility that interconnects with an electric system other than the Company's electric system may enter into a PPA with the Company after following the applicable Standard or Negotiated PPA guidelines and making the arrangements necessary for transmission of power to the Company's system.

BASIS FOR POWER PURCHASE PRICE

AVOIDED COST SUMMARY

The power purchase prices are based on either the Company's Standard Avoided Costs or Renewable Avoided Costs in effect at the time the agreement is executed. Avoided Costs are defined in 18 CFR 292.101(6) as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."

Monthly On-Peak prices are included in both the Standard Avoided Costs as listed in Tables 1a, 2a, and 3a and Renewable Avoided Costs as listed in Tables 4a, 5a, and 6a. Monthly Off-Peak prices are included in both the Standard Avoided Costs as listed in Tables 1b, 2b, and 3b and Renewable Avoided Costs as listed in Tables 4b, 5b, and 6b.

ON-PEAK PERIOD

The On-Peak period is 6:00 a.m. until 10:00 p.m., Monday through Saturday.

OFF-PEAK PERIOD

The Off-Peak period is 10:00 p.m. until 6:00 a.m., Monday through Saturday, and all day on Sunday.

Standard Avoided Costs are based on forward market price estimates through the Resource Sufficiency Period, the period of time during which the Company's Standard Avoided Costs are associated with incremental purchases of Energy and capacity from the market. For the Resource Deficiency Period, the Standard Avoided Costs reflect the fully allocated costs of a natural gas fueled combined cycle combustion turbine (CCCT) including fuel and capital costs. The CCCT Avoided Costs are based on the variable cost of Energy plus capitalized Energy costs at a 93% capacity factor based on a natural gas price forecast, with prices modified for shrinkage and transportation costs.

Renewable Avoided Costs are based on forward market price estimates through the Renewable Resource Sufficiency Period, the period of time during which the Company's Renewable Avoided Costs are associated with incremental purchases of energy and capacity from the market. For the Renewable Resource Deficiency Period, the Renewable Avoided Costs reflect the fully allocated costs of a wind plant including capital costs.

PRICING FOR STANDARD PPA

Pricing represents the purchase price per MWh the Company will pay for electricity delivered to a Point of Delivery (POD) within the Company's service territory pursuant to a Standard PPA up to the nameplate rating of the QF in any hour. Any Energy delivered in excess of the nameplate rating will be purchased at the applicable Off-Peak Prices for the selected pricing option.

The Standard PPA pricing will be based on either the Standard or Renewable Avoided Costs in effect at the time the agreement is executed.

The Company will pay the Seller either the Off-Peak Standard Avoided Cost pursuant to Tables 1b, 2b, or 3b or the Off-Peak Renewable Avoided Costs pursuant to Tables 4b, 5b, or 6b for: (a) all Net Output delivered prior to the Commercial Operation Date; (b) all Net Output deliveries greater than Maximum Net Output in any PPA year; (c) any generation subject to and as adjusted by the provisions of Section 4.3 of the Standard PPA; (d) Net Output delivered in the Off-Peak Period; and (e) deliveries above the nameplate capacity in any hour. The Company will pay the Seller either the On-Peak Standard Avoided Cost pursuant to Tables 1a, 2a, or 3a or the On-Peak Renewable Avoided Costs pursuant to Tables 4a, 5a, or 6a for all other Net Output. (See the PPA for defined terms.)

Standard Fixed Price Option 1)

The Standard Fixed Price Option is based on Standard Avoided Costs including forecasted natural gas prices. It is available to all QFs.

This option is available for a maximum term of 15 years. Prices will be as established at the time the Standard PPA is executed and will be equal to the Standard Avoided Costs in Tables 1a and 1b, 2a and 2b, or 3a and 3c, depending on the type of QF, effective at execution. QFs using any resource type other than wind and solar are assumed to be Base Load QFs.

Prices paid to the Seller under the Standard Fixed Price Option include adjustments for the capacity contribution of the QF resource type relative to that of the avoided proxy resource. Both the Base Load QF resources (Tables 1a and 1b) and the avoided proxy resource, the basis used to determine Standard Avoided Costs for the Standard Fixed Price Option, are assumed to have a capacity contribution to peak of 100%. The capacity contribution for Wind QF resources (Tables 2a and 2b) is assumed to be 5%. The capacity contribution for Solar QF resources (Tables 3a and 3b) is assumed to be 5%.

Prices paid to the Seller under the Standard Fixed Price Option for Wind QFs (Tables 2a and 2b) include a reduction for the wind integration costs in Table 7. However, if the Wind QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the wind integration charges in Table 7, in addition to the prices listed in Tables 2a and 2b, for a net-zero effect.

Portland General Electric Company

Sheet No. 201-5

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

Sellers with PPAs exceeding 15 years will receive pricing equal to the Mid-C Index Price for all years up to five in excess of the initial 15.

						LE 1a								
					Avoide	d Costs	D.as.l	and OF						
			Stan	dard Fixe	d Price C	option fo	r Base L	Oau Gi						
				On-F	eak For	ecast (\$/	MAN LI)					Dec		
							Jul	Aug	Sep	Oct	1404	31.46		
		Feb	Mar	<u>~~</u>	May	Jun 16.06	23.96	26.96	24.96	23.71		33.71		
Year	Jan	22,46	15.61		12.46	16.96	27.96	30.96	29.46	27.71	28.71 31.86	35.71		
2016	28.21	28.21	24.71	20.96	19.46	20.46	29.93	33.37	30.63	28.61	32.52	38.21		
2017	29.96 31.71	31.11	28.11	22.13	21.28	23.13	31.67	35.08	33.37	31.38	34.24	40.24		
2018	33.94	31.95	27.97	23.70	22.00	24.35	33.34	36.94	35.14	33.04		68.72		
2019	35.74	33.64	29.45	24.95	23.15	64.50	64.61	64.73	64.84	65.48	68.60	71.70		
2020		67.34	65.41	64.69	64.41		67.04	67.17	67.29	67.83	71.38	73.70		
	2021 67.43 67.34 63.41 67.13 66.81 66.91 67.04 67.17 69.58 70.12 73.56 73.70 2022 69.01 68.84 68.08 67.13 69.07 69.18 69.31 69.45 69.58 70.12 73.56 73.70 2022 74.95 71.76 70.39 69.19 69.07 69.18 69.31 69.45 69.58 70.12 73.56 73.70 2023 74.95 71.76 70.39 69.19 69.07 71.31 71.50 71.63 72.20 76.49 76.64 30.00 73.70 74.24 71.35 71.50 71.63 72.20 76.49 76.64													
			70.39											
2023	74.17	73.85	72.67	71.29	71.10	75.14	75.30	75.47	75.62	75.80	89.02	88.72		
2024	77.19	77.30	75.84	74.88	75.02	81.36	81.56	81.74	81.90	82.36	91.39	91.15		
2025	85.18	85.30	82.77	81.28	81.22	83.03	83.00		83.46	83.97	94.66	93.5		
2026	86.85		85.14	83.12	82.89	85.46		7 25 24	85.95	86.65	98.37	98.1		
2027	89.32		87.96	85.46	85.30	88.15			88.61	89.34	100 10	102.7		
2028	94.06		91.23	88.74	87.97	92.57						104.7		
2029	97.60		- 4 07	92.62	92.40	1 10		-1				109.4		
2030	99.56		1 70	94.48	94.26	45		3 98.65				112.2		
2031	103.85			98.18	97.96				101.32			114.9		
2032	106.56		103.17									117.		
2033	109.12		7 105.60					3 105.8						
2034	111.5		1 107.91					0 108.0				100		
2035	113.8		0 110.14		100.00			14 110.6			<u> </u>			
2036	116.5		5 112.7				- 1							
2037	119.0	-1-100	3 115.2					85 115.3						
2038	121.4		12 117.5				41 117.							
2039	124.2		20 120.2					85 120.	36 120.	49 121.4				
2040	126.		67 122.6	4 119.7	0 1 119.									

						LE 1b						
					Avoide	d Costs	. Dece 1	oad OF				
			Stan	dard Fixe	d Price C	option for	Base L	Oau Gi				
				Off-	Peak For	ecast (\$/	MAA LI)					
						lun	Jul	Aug	Sep	Oct	Nov	Dec
Year	Jan	Feb	Mar	_ 	May	Jun 10.11	15.71	20.96	20.96	21.21	23.46	26.71 27.96
2016	25.61	20.71	13.96	11.41	6.31	12.71	19.71	25.21	25.46	24.71	25.71	30,62
2017	25.71	24.21	22.21	15.71	13.71	12.54	19.71	27.04	26.93	25.35	28.20	32.47
2018	26.17	28.12	25.56	19.46	14.68	14.64	22.83	29.26	29.55	28.67	29.84	34.55
2019	29.84	28.09	25.75	18.15	15.81	15.54	24.27	31.12	31.43	30.50	31.75	30.18
2020	31.75	29.88	27.38	19.28	25.87	25.95	26.07	26.19	26.30	26.94	30.06	32,42
2021	28.88	28.79	26.86	26.15 27.85	27.53	27.63	27.75	27.88	28.00	28.54 29.95	33.38	33.52
2022	29.73	29.56	28.79	29.01	28.90	29.00	29.14	29.27	29.40	31.51	35.80	35.96
2023	31.78	31.59	30.21	30.60	30.41	30.52	30.66	30.81	30.95	34.19	40.97	41.28
2024	33.48	33.16	34.24	33.27	33.42	33.53	33.70	33.86	34.01 39.50	39.95	46.62	46.31
2025	35.58	35.69	40.36	38.87	38.81	38.95	39.15	39.34	40.24	40.74	48.16	47.92
2026	42.77	42.89	41.91	39.89	39.66	39.80	39.77	40.09	41.89	42.59	50.60	49.48
2027	43.63	43.54 45.25	43.90	41.40	41.23	41.40	41.25	41.58	43.70	44.43	53.46	53.20
2028	45.26	49.08	46.32	43.83	43.06	43.24	42.80	43.15	47.34	47.90	56.64	56.92
2029	49.15	51.76	49.09	46.84	46.62	46.79	46.83	48.21	48.33	48.90	57.81	58.10
2030	51.82	52.84	50.11	47.82	47.59	47.77	47.81			52.10	61.60	62.15
2031	52.90			50.92	50.70	50.89	50.97			53.45	63.19	63.78
2032	56.59 58.08	+		52.24	52.02	52.21	52.30					65.39
2033	59.54			53.52	53.30	53.50				56.26		67.1
2034	61.18			54.98	54.75			<u> </u>		57.65		68.7
2035	62.67						== 0					
2036	64.17			57.73			-	-				
2037	65.7						4					
2038			46				-	<u> </u>				
2039			8 64.83	3 62.01						9 64.7	1 76.19	76.9
2040			7 66.1	4 63.27	63.02	2 63.2	00.0					
2041												

	•														
						TAB	LE 2a								
						Avoide	d Costs	i		LOE					
			•	Standar	d Fix	ed Pric	e Option	n fo	r Win	a ur					
				C	n-Pe	ak For	ecast (\$	/NV	VH)						
									ul	Aug	S	ер	Oct	Nov	Dec 27.62
		Feb	Mar	Apr		lay	Jun		0.12	23.12	2	1.12	19.87	22.87	29.80
Year	Jan 27	18.62	11.77	10.87	4	8.62	13.12		4.05	27.05	2	5.55	23.80	24.80	31.72
2016	24.37	24.30	20.80	17.05		5.55	16.55 17.29		5.94	29.38	2	6.64	24.62	27.87	34.14
2017	26.05 27.72	27.12	24.12	18.14	-	7.29	19.06	_	7.60	31.01	1 2	29.30	27.31	30.09	36.09
2018	29.87	27.88	23.90	19.63		7.93	20.20		9.19	32.79		30.99	28.89	31.86	31.98
2019	31.59	29.49	25.30	20.80		19.00	27.75		7.87	27.99		28.10	28.74	33.93	34.25
2020	30.68	30.59	28.66	27.94		27.66	29.46	I	29.59	29.72		29.84	30.38	35.28	35.42
	2021 31.56 31.39 30.62 29.68 29.30 20.00 31.03 31.17 31.30 31.64 50.20 2022 31.56 31.39 30.91 30.79 30.90 31.03 31.17 31.30 31.64 50.20 37.70 37.85														
2022	33.67	33.48	32.11	-		32.30	32.42	1:	32.56				36.14	42.91	43.23
2024	35.38	35.06	33.88		<u> </u>	35.36	35.48		35.64	35.8		35.96	41.94	48.60	48.29
2025	37.53	37.64				40.79	40.94	_	41.13	41.3		41.48 42.26	42.76		49.94
2026	44.75	44.87				41.68	41.82		41.79			43.95	44.65		51.55
2027	45.65	45.56			-	43.30	43.46	5	43.31			45.80	46.53		55.30
2028	47.32	47.3				45.16	45.34	1	44.90			49.48			
2029	51.25					48.76	48.93		48.97			50.51			
2030	53.96			<u></u>		49.77	49.9		49.99		_	53.68		63.78	
2031	55.08				10	52.88			53.1		.00	55.11		2 65.4	
2032	58.7				.51	54.29	54.4		54.5		.37	56.48	3 57.1		
2033	60.3		<u></u>		.86	55.63			55.9 57.4		.87	57.9	8 58.6		
2034	61.8				.34	57.11			58.8		.27	59.3			
2035	63.5		70	33 58	3.72	58.49			60.2).73	60.8			
2036	00.0		301	83 60	0.17	59.9			61.		2.23	62.3			
2037					1.66	61.4			63.		3.52	63.6			
2038		==-			2.94	62.7			64.	68 6	5.18				<u></u>
2039	<u></u>			• •	4.60	64.3	,	.90	66.		6.52	66.0	64 67.	30 1 70.	<u> </u>
2040	70			3.79	5.92	65.6	00 1 00	.00							
2041	1														

						E 2b						
					Avoide	d Costs						
			St	andard Fi	xed Pric	e Option	for Win	d QF				
				Off-F	eak For	ecast (\$/	MWH)					
								Aug	Sep	Oct	1404	Dec
	100	Feb	Mar	Apr	May	Jun	Jul 11.87	17.12	17.12	17.37		22.87
Year	Jan 21.77	16.87	10.12	7.57	2.47	6.27	15.80	21.30	21.55	20.80		24.05
2016	21.80	20.30	18.30	11.80	9.80	8.80	15.72	23.05	22.94	21.36	24.21	26.63
2017	22.18	24.13	21.57	15.47	10.69	8.55	18.76	25.19	25.48	24.60	25.77	28.40
2018	25.77	24.02	21.68	14.08	11.74	10.57	20.12	26.97	27.28	26.35	27.60	30.40
2019	27.60	25.73	23.23	15.13	12.64	21.72	21.84	21.96	22.07	22.71	25.83	25.95 28.11
2020	24.65	24.56	22.63	21.92	21.64	23.32	23.44	23.57	23.69	24.23	27.78	29.13
2021 2022	25.42	25.25	24.48	23.54	23.22	24.61	24.75	24.88	25.01	25.56	28.99	31.49
2023	27.39	27.20	25.82	24.62 26.13	25.94	26.05	26.19	26.34	26.48	27.04 29.63	36.41	36.72
2024	29.01	28.69	27.51	28.71	28.86	28.97	29.14	29.30	29.45	35.30	41.97	41.66
2025	31.02	31.13	29.68	34.22	34.16	34.30	34.50	34.69	34.85	36.00	43.42	43.18
2026	38.12	38.24	35.71	35.15	34.92	35.06	35.03		35.50	37.76	45.77	44.65
2027	38.89	38.80	37.17	36.57	36.40	36.57	36.42			39.51	48.54	48.28
2028	40.43	40.42	39.07 41.40	38.91	38.14	38.32	37.88			42.88	51.62	51.90
2029	44.23	44.16	44.07	41.82	41.60	41.77	41.81			43.78	52.69	52.98
2030	46.80	46.74		42.70	42.47	42.65	42.69				56.39	56.94
2031	47.78			45.71	45.49	45.68	45.70					58.47
2032	51.38				46.71	46.90	46.9	<u> </u>				59.9
2033	52.77			48.10	47.88	48.08	48.1				60.98	61.6
2034	54.12			49.46	49.23					52.02		63.1
2035	55.66 57.04				50.49							64.6
2036	58.4				51.75		+					66.2
2037	59.8			53.32				10				67.6
2038	61.1	<u> </u>										<u> </u>
2039	62.7	<u> </u>								0 58.5	2 70.00	/0.
2040	64.0			5 57.08	56.8	3 51.0	<u> </u>					

indard F	ixed Pi	ice Obr	1011 (00									
				TAE	LE 3a							
				Avoid	ed Costs	n for !	Solar	QF				
		5	standard	Fixed Price	e Optio	AWW.	<u>30141</u> 41					
			Or	-Peak Fo	recast (4	I IAIAA	<u>'/</u>					Dec
					T	hul	\top	Aug	Sep			31.46
	Feb	Mar	Apr									33.71
		15.61	14.71					30.96	29.46			35.71
		24.71	20.96					33.37	30.63			38.21
		28.11						35.08	33.37			40.24
		27.97						36.94	35.14			35.27
		29.45						31.28	31.39			37.61
		31.96	31.24					33.08	33.20			38.83
		33.98	33.04					34.58	34.71			41.33
		35.52	34.32					36.19	36.32			46.78
		37.36				+		39.36	39.51	15.50		51.91
					1			44.94			07	53.63
				1 200				45.81				55.31
	10.05		·					47.40				1 70 40
1		10 70		10.00				49.08				
			3 49.7					53.27				
								54.37				
			·		-			57.64				
								59.1				
		4 61.0						60.5				
											<u></u>	
1		38 65.	·		<u>~</u>							
			<u> </u>								<u> </u>	
								7 68.				
							69.4			·		
		10 72		.00	00				34 71	.46 12	11 1 00.	
·		.64 73	.61 70	.74 70.	40 1 10							
	Jan 28.21 29.96 31.71 33.94 35.74 33.98 34.92 37.09 38.86 41.08 48.37 49.34 51.08 57.87 59.0 62.8 64.4 66.1 67.8 69.4 71.0 72. 74.	Jan Feb 28.21 22.46 29.96 28.21 31.71 31.11 33.94 31.95 35.74 33.64 33.98 33.89 34.92 34.75 37.09 36.90 38.86 38.54 41.08 41.19 48.37 48.49 49.34 49.25 51.08 51.07 55.08 55.0 57.87 57.8 59.07 59.0 62.83 62.7 64.49 64.4 66.10 66.0 67.84 67. 69.43 69. 71.08 71. 72.78 72. 74.28 74. 76.15 76	Jan Feb Mar 28.21 22.46 15.61 29.96 28.21 24.71 31.71 31.11 28.11 33.94 31.95 27.97 35.74 33.64 29.45 33.98 33.89 31.96 34.92 34.75 33.98 37.09 36.90 35.52 38.86 38.54 37.36 41.08 41.19 39.73 48.37 48.49 45.97 49.34 49.25 47.62 51.08 51.07 49.72 55.08 55.01 52.26 57.87 57.81 55.1 59.07 59.00 56.2 62.83 62.78 59.5 64.49 64.44 61.0 66.10 66.05 62.5 67.84 67.79 64.3 69.43 69.38 65. 71.08 71.04 67. 72.78	Jan Feb Mar Apr 28.21 22.46 15.61 14.71 29.96 28.21 24.71 20.96 31.71 31.11 28.11 22.13 33.94 31.95 27.97 23.70 35.74 33.64 29.45 24.95 33.98 33.89 31.96 31.24 37.09 36.90 35.52 34.32 38.86 38.54 37.36 35.98 41.08 41.19 39.73 38.77 48.37 48.49 45.97 44.48 49.34 49.25 47.62 45.61 51.08 51.07 49.72 47.22 55.08 55.01 52.26 49.7 57.87 57.81 55.14 52.8 59.07 59.00 56.28 53.9 62.83 62.78 59.56 57.1 64.49 64.44 61.09 58.6 67.84 67.79	Standard Fixed Price	TABLE 3a Avoided Costs Standard Fixed Price Option On-Peak Forecast (\$ 28.21 22.46 15.61 14.71 12.46 16.96 29.96 28.21 24.71 20.96 19.46 20.46 31.71 31.11 28.11 22.13 21.28 21.28 33.94 31.95 27.97 23.70 22.00 23.13 35.74 33.64 29.45 24.95 23.15 24.35 33.98 33.89 31.96 31.24 30.96 31.05 37.09 36.90 35.52 34.32 34.21 34.31 38.86 38.54 37.36 35.98 35.79 35.90 38.86 38.54 37.36 35.98 35.79 35.90 48.37 48.49 45.97 44.48 44.42 44.56 49.34 49.25 47.62 45.61 45.38 45.51 55.08 55.01 <td< th=""><th> TABLE 3a Avoided Costs Standard Fixed Price Option for Standard Fixed Fi</th><th> Standard Fixed Price Option for Solar On-Peak Forecast (\$/MWH)</th><th> Standard Fixed Price Option for Solar QF </th><th> Standard Fixed Price Option for Solar QF</th><th> Note</th><th> Noticed Costs Standard Fixed Price Option for Solar QF </th></td<>	TABLE 3a Avoided Costs Standard Fixed Price Option for Standard Fixed Fi	Standard Fixed Price Option for Solar On-Peak Forecast (\$/MWH)	Standard Fixed Price Option for Solar QF	Standard Fixed Price Option for Solar QF	Note	Noticed Costs Standard Fixed Price Option for Solar QF

Sta	ndard Fi	xea Fii	Ce Ob"	··· (
					TAB	LE 3b							
					Avoide	d Costs	for Sol	ar QF					
			S	tandard l	Avoide Fixed Price	e Option	(MM/H)						-
				Off	-Peak For	ecast (a	MANATA				T	Nov	Dec
						lun	Jul	Aug		ep	Oct	23.46	26.71
	Jan T	Feb	Mar	Apr	May	Jun 10.11	15.71	20.		0.96	21.21	25.71	27.96
Year	Jan 25.61	20.71	13.96	11.41	6.31	12.71	19.71	25.		5.46	24.71	28.20	30.62
2016	25.71	24.21	22.21	15.71	13.71	12.54	19.71	27.		26.93	25.35 28.67	29.84	32.47
2017	26.17	28.12	25.56	19.46	14.68	14.64	22.83			29.55	30.50	31.75	34.55
2018	29.84	28.09	25.75	18.15	15.81	15.54	24.27			31.43	26.94	30.06	30.18
2019	31.75	29.88	27.38	19.28	16.79 25.87	25.95	26.07			26.30	28.54	32.09	32.42
2020	28.88	28.79	26.86	26.15	25.87	27.63	27.75		7.88	28.00 29.40	29.95	33.38	33.52
2021	29.73	29.56	28.79	27.85	28.90	29.00	29.14		9.27	30.95	31.51	35.80	35.96
2022 2023	31.78	31.59	30.21	29.01 30.60	30.41	30.52	30.66	-	0.81	34.01	34.19	40.97	41.28
2023	33.48	33.16	31.98	33.27	33.42	33.53	33.70		3.86	39.50	39.95	46.62	46.31
2025	35.58	35.69	34.24	38.87		38.95			9.34	40.24	40.74	48.16	47.92
2026	42.77	42.89	40.36	+	20.00	39.80			10.09	41.89	42.59	50.60	49.48
2027	43.63	43.54			11.00	41.40	41.2		11.58 43.15	43.70	44.43		1 01
2028	45.26					43.24			47.22	47.34	47.90		
2029	49.15	49.08		100	10.00	46.79	_ , _ ,		48.21	48.33			
2030	51.82								51.39	51.50		0 61.60	
2031	52.90					50.8			52.73	52.84		5 63.19	
2032	56.59	^							54.04	54.1	54.7		
2033	58.08	c -			2 53.3				55.52	55.6	2 56.2		<u></u>
2034	59.5	4				5 54.9	70-	43	56.89	57.0	0 57.6		
2035	61.1				35 56.1			.80	58.28	58.3			
2036	62.6				73 57.4			.25	59.73	59.8			
2037	64.1				17 58.9			.48	60.98	61.0			
2038	65.7				40 60.			2.09	62.60				
2039	67.0	00 1	<u> </u>		.01 61.			3.36	63.87		99 64	.71 76.	19 1 70
2040					.27 63.	02 63	.25 63	2.00					
2041	70.	23 70.	11-1-00										

PRICING OPTIONS FOR STANDARD PPA (Continued)

2) Renewable Fixed Price Option

The Renewable Fixed Price Option is based on Renewable Avoided Costs. It is available only to Renewable QFs that generate electricity from a renewable energy source that may be used by the Company to comply with the Oregon Renewable Portfolio Standard as set forth in ORS 469A.005 to 469A.210.

This option is available for a maximum term of 15 years. Prices will be as established at the time the Standard PPA is executed and will be equal to the Renewable Avoided Costs in Tables 4a and 4b, 5a and 5b, or 6a and 6b, depending on the type of QF, effective at execution. QFs using any resource type other than wind and solar are assumed to be Base Load QFs.

Sellers will retain all Environmental Attributes generated by the facility during the Renewable Resource Sufficiency Period. A Renewable QF choosing the Renewable Fixed Price Option must cede all RPS Attributes generated by the facility to the Company from the start of the Renewable Resource Deficiency Period through the remainder of the PPA term.

Prices paid to the Seller under the Renewable Fixed Price Option include adjustments for the capacity contribution of the QF resource type relative to that of the avoided proxy resource. Both Wind QF resources (Tables 5a and 5b) and the avoided proxy resource, the basis used to determine Renewable Avoided Costs for the Renewable Fixed Price Option, are assumed to have a capacity contribution to peak of 5%. The capacity contribution for Solar QF resources (Tables 6a and 6b) is assumed to be 5%. The capacity contribution for Base Load QF resources (Tables 4a and 4b) is assumed to be 100%.

The Renewable Avoided Costs during the Renewable Resource Deficiency Period reflect an increase for avoided wind integration costs, shown in Table 7.

Prices paid to the Seller under the Renewable Fixed Price Option for Wind QFs (Tables 5a and 5b) include a reduction for the wind integration costs in Table 7, which cancels out wind integration costs included in the Renewable Avoided Costs during the Renewable Resource Deficiency Period. However, if the Wind QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the wind integration charges in Table 7, in addition to the prices listed in Tables 5a and 5b.

Sellers with PPAs exceeding 15 years will receive pricing equal to the Mid-C Index Price for all years up to five in excess of the initial 15.

Re	newable	Fixedi	1100 01									
					TAB	LE 4a						
				Ren	ewable /	Avoided (30515 Boso i	oad QF				
			Renev	Ren wable Fix	ed Price	Option to	MMMH	LOUG 4				
				On-	Peak For	ecast (\$/	IVIVVII					Dec
						 -	Jul	Aug	Sep	Oct	Nov	31.61
	T	Feb	Mar	Apr	May	Jun	24.11	27.11	25.11	23.86	26.86	33.86
Year	Jan	22.61	15.76	14.86	12.61	17.11	28.11	31.11	29.61	27.86	28.86	35.86
2016	28.36	28.36	24.86	21.11	19.61	20.61	30.08	33.52	30.78	28.76	32.01	38.37
2017	30.11	31.26	28.26	22.28	21.43	21.43	31.83	35.24	33.53	31.54	32.68	114.45
2018	31.86	32.11	28.13	23.86	22.16	23.29	117.01	116.89	115.60	114.63	115.47	117.22
2019	34.10	115.32	114.56	110.0-1	118.22	117.33	119.26	119.77	118.26	117.25	118.55	119.53
2020	115.34	118.18	116.67	117.75	120.59	119.83	121.69	121.65	120.55	119.55	120.98	122.53
2021	117.94	120.36	118.46	120.19	123.17	122.14	124.29	123.92	123.08	121.92	123.63	124.96
2022	120.48	122.83	120.85	122.92	125.37	124.64	124.23	126.41	126.22	123.83	124.83	127.41
2023	123.26	125.01	123.06	125.07	127.80	126.78	129.53	129.66	128.84	126.59	127.76	130.23
2024	124.86	128.05	125.86	128.21	131.66	130.48	132.28	132.69		129.34	131.17	132.78
2025	127.73	130.58	129.12	131.30	135.76	132.28	134.51	135.95		131.96	133.26	135.00
2026	130.91	133.03	131.38	133.50	139.48	134.88	137.64			134.76		138.2
2027	133.47		132.89	136.24	141.79	136.93						140.7
2028	135.95	138.57	135.91	139.29	149.30	140.74	1 10 05			140.18		
2029	138.81	1		142.00	153.18					143.04		
2030	141.68			145.52	156.10			1			146.37	
2031	144.29	110.00		147.76	158.51							
2032	146.5				162.18					3 151.6		
2033	149.9			1 - 4 00	165.46						1 - 2 4	
2034	152.9				168.5			1000		3 156.9		
2035	155.7	1			5 171.2	4		~		1 160.4		
2036	158.3				175.0					9 163.5		
2037	161.8				5 178.4					13 166.6		
2038	164.9				6 181.8					10 169.		
2039	168.1				1 185.0					80 173.	18 174.5	02 1/3
2040	171.				7 188.9	8 180.	12 110.	70 1 111				
2041	174.	09 174.1	00 112.									

Re	enewable	Fixea	Price O	ption (
					TAB	LE 4b							
				Rei	newable /	Avoided	Costs	. Los	ad OF	_			
			Rene	Rei wable Fix	ced Price	Option 1	OF DASE	; LU	<u>uu </u>				
				Off-	Peak For	ecast (\$	/ WINA 1 1)						D-0
							Jul	A	lug	Sep	Oct	Nov	Dec 26.86
	lon	Feb	Mar	Apr	May	Jun 10.26	15.86		1.11	21.11	21.36	23.61	28.11
Year	Jan 25.76	20.86	14.11	11.56	6.46	12.86	19.86		25.36	25.61	24.86	25.86	30.77
2016	25.86	24.36	22.36	15.86	13.86	12.69	19.86	1 2	27.19	27.08	25.50	28.35	32.63
2017	26.32	28.27	25.71	19.61	14.83	14.80	22.99		29.42	29.71	28.83	30.00	63.99
2018	30.00	28.25	25.91	18.31	15.97	60.16	60.45	_	61.61	62.52	63.74	63.55 63.38	65.09
2019	62.76	63.02	64.56	63.31	59.92	61.62	62.27	7	62.62	63.78	65.82	64.42	66.29
2020	64.93	64.15	65.85	64.48	61.58	62.82	64.33	_	63.35	65.00	67.04	65.38	67.63
2021	65.85	65.52	67.77	65.49	62.45	64.01	65.40		64.85	66.14	68.41	67.42	68.05
2022 2023	66.70	66.75	69.10	67.28	62.84 63.18	65.92	64.7		65.12	66.62	68.68	69.68	69.06
2023	67.25	67.31	70.47	67.09	63.17	66.28	66.1	2	67.12	67.23	70.19 71.12	69.85	69.89
2025	68.62	68.60	71.94	68.08	63.85	67.22			67.75	67.05	73.22	70.67	71.18
2026	68.95	69.85	72.28	68.56	63.69	68.45		9	68.16	68.57	+	71.48	73.4
2027	71.31	71.29	73.13		63.09	69.98		5	68.82	70.20			74.6
2028	72.28				1 205	70.29		37	70.00	71.53			76.2
2029	72.78	73.60)2	72.19	72.00	-		76.3
2030	73.91						7 73.		73.71	72.16	-		77.5
2031	75.51						3 74.		74.93	73.35			79.2
2032	76.76	77.9					2 76.		76.58				80.8
2033	78.46						4 77.		78.06			- 10	82.3
2034	79.9					7 76.2		39	79.57				
2035	81.5					3 77.5		.70	80.88	<u> </u>			85.
2036	82.8							.49	82.6 84.2				
2037	84.6					4 80.7	-	.08	85.8			1 89.8	
2038	86.3		~					5.70	87.3			19 91.2	
2039	87.9				6 70.0		101-	7.12		-+			1 92
2040	89.					85.	55 89	9.04	1_09.2	<u> </u>	1		
204	1 91.	42 92.	00 30.	19 1									

Rei	newable	Fixeu	1100 01	,,,,,,								
					TAB	LE 5a	Costs					
				Ren	ewable A	voldeu C	n for Wir	nd QF				
			Re	Ren newable	Fixed Pri	ce Option	MWH)					
				On-	Peak For	ecast (w	1010 1 1			 -	Nov	Dec
						Jun	Jul	Aug	Sep	Oct	23.02	27.77
	lan	Feb	Mar	Apr	May	13.27	20.27	23.27	21.27	20.02	24.95	29.95
Year	Jan 24.52	18.77	11.92	11.02	8.77	16.70	24.20	27.20	25.70	23.95	28.02	31.87
2016	26.20	24.45	20.95	17.20	15.70	17.44	26.09	29.53	26.79	24.77 27.47	28.61	34.30
2017	27.87	27.27	24.27	18.29	17.44	19.22	27.76	31.17	29.46		75.51	74.49
2018	30.03	28.04	24.06	19.79	18.09	77.37	77.05	76.93	75.64	74.67 76.40	77.70	76.38
2019	75.38	75.37	74.61	75.06	78.26	78.99	78.41	78.92	77.41	77.92	79.34	77.90
2020	77.10	77.33	75.83	76.90	79.75 81.53	80.51	80.05	80.02	78.92		81.08	79.97
2021	78.85	78.72	76.82	78.56	82.82	82.08	81.73	81.37	80.53		81.71	81.84
2022	80.71	80.27	78.29	80.37	84.68	83.66	83.55	83.28			83.68	83.32
2023	81.74	81.89	79.93	81.95	87.57	86.40	85.44	85.57		1 10		85.29
2024	83.64	83.97	81.78	84.13	90.82	87.34	87.34	87.75				86.98
2025	85.97	85.64	84.18	86.37	93.67	89.07	88.71					
2026	87.67	87.23	85.57	87.69	95.10	90.24	90.95					
2027	89.26	88.22	86.20	89.55	101.72	93.16						92.2
2028	91.22				104.67	96.69						94.2
2029	93.17		90.60			+		97.2				95.8
2030 2031	94.84		92.72		-1		97.8					
2031	96.40	95.90					2 100.0					9 99.
2032	98.5	98.03					2 101.9					
2034	100.4	4 99.9			-		6 103.9			<u> </u>	9 103.9	
2035	102.3	8 101.8				1 109.5	3 105.6					1 105
2036	104.0	6 103.5				1 111.9	6 107.9				00 108.2	
2037	106.3	7 105.8					12 110.			<u> </u>		
2038	108.4	12 107.8									85 112.	
2039	110.5						23 114.					66 114
2040	112.						86 116	.55 117	.08 [111	<u> </u>		
204	_ 1 444	83 114.	23 112.3	20 1 10.								

Re	newable	Fixed	PIICE O	puon (-									
					TAE	LE 5b							
				Re	newable	Avoided	Costs	nd O	F				
			Re	enewable	Fixed Pr	ice Optio	UNWALLI)	iiu Q	·				
				Off	Peak Fo	recast (\$	/IVIVV FT)						
					—		Jul	Au	a s	Sep	Oct	Nov	Dec 23.02
	Jan	Feb	Mar	Apr	May	Jun 6.42	12.02	17.		17.27	17.52	19.77	24.20
Year	21.92	17.02	10.27	7.72	2.62	8.95	15.95	21.		21.70	20.95	21.95	26.78
2016	21.95	20.45	18.45	11.95	9.95	8.70	15.87		.20	23.09	21.51	24.36	28.56
2017	22.33	24.28	21.72	15.62	10.84	10.73	18.92	25	.35	25.64	24.76	25.93	59.84
2018	25.93	24.18	21.84	14.24	11.90	56.01	56.30		7.46	58.37	59.59	59.40	60.86
2019	58.61	58.87	60.41	59.16	55.77	57.39	58.04		3.39	59.55	61.59	59.15	61.98
2020	60.70	59.92	61.62	60.25	57.35	58.51	60.02	59	9.04	60.69	62.73	60.11	63.24
2021	61.54	61.21	63.46	61.18	58.14	59.62	61.01	60	0.46	61.75	64.02	60.99 62.95	63.58
2022	62.31	62.36	64.71	62.89	58.45	61.45	60.28	60	0.65	62.15	64.21	65.12	64.50
2023 2024	62.78	62.84	66.00	62.62	58.71	61.72	61.56		2.56	62.67	65.63	65.20	65.24
2025	64.06	64.04	67.38	63.52	58.61 59.20	62.57	62.40) 6	3.10	62.40	66.47 68.48	65.93	66.44
2026	64.30	65.20	67.63		- 2 2 5	63.71	64.0		3.42	63.83	68.96	+	68.58
2027	66.57	66.55	68.39			65.15			33.99	65.37	69.66		69.76
2028	67.45	68.07	70.58			_			65.08	66.61	70.97	1	71.21
2029	67.86	68.68							67.17	66.98	72.12		71.19
2030	68.89						68.4		68.59	67.04			72.36
2031	70.39						69.5		69.72	68.14			73.9
2032	71.55	72.76							71.27	69.66 71.00	1 20		75.4
2033	73.15						2 72.4	''	72.64	72.37			76.8
2034	74.5					5 70.7			74.05	73.55			78.1
2035	76.0							_	75.25	75.19			
2036	77.2					2 73.5			76.93	76.6			81.3
2037						9 74.9			78.41			5 83.8	
2038	80.4							74	79.93 81.23			11 85.2	
2039	82.0							04	83.05				2 86.
2040	83.3					14 79.	36 82	.85	03.00	2 1 0 1.1			
2041	85.2	23 86.6	00.										

TABLE 6a													
Renewable Avoided Costs													
	Renewable Fixed Price Option for Solar QF												
	On-Peak Forecast (\$/MWH)												
					<u>-</u> -		Test	Aum	Sep	Oct	Nov	Dec	
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug 27.11	25.11	23.86	26.86	31.61	
2016	28.36	22.61	15.76	14.86	12.61	17.11	24.11	31.11	29.61	27.86	28.86	33.86	
2017	30.11	28.36	24.86	21.11	19.61	20.61	28.11 30.08	33.52	30.78	28.76	32.01	35.86	
2018	31.86	31.26	28.26	22.28	21.43	21.43		35.24	33.53	31.54	32.68	38.37	
2019	34.10	32.11	28.13	23.86	22.16	23.29	31.83	80.17	78.88	77.91	78.74	77.73	
2020	78.62	78.60	77.84	78.30	81.50	80.60	80.29		80.71	79.70	81.00	79.67	
2021	80.39	80.63	79.12	80.20	83.04	82.28	81.71	82.22	82.27	81.27	82.70	81.25	
2022	82.21	82.08	80.18	81.92	84.89	83.87	83.41	83.38	83.94	82.78	84.50	83.39	
2023	84.12	83.69	81.71	83.78	86.23	85.50	85.15	84.78	86.58	84.19	85.19	85.32	
2024	85.22	85.37	83.41	85.43	88.16	87.14	87.03	86.76	88.30	86.06	87.23	86.87	
2025	87.19	87.52	85.33	87.68	91.12	89.95	88.99	89.12		88.02	89.85	88.91	
2026	89.59	89.26	87.80	89.99	94.44	90.96	90.96	91.37	91.08 92.68	89.85	91.14	90.67	
2027	91.36	90.92	89.26	91.39	97.36	92.76	92.40	93.84		91.84	92.91	92.13	
2028	93.02	91.98	89.96	93.31	98.86	94.00	94.71	94.72	93.84 97.11	93.75	94.56	94.45	
2029	95.05	94.81	92.15	95.53	105.55	96.99	97.06	97.06		95.58	96.15	96.19	
2030	97.08	96.79	94.51	97.40	108.58	100.60	98.45	98.33	99.71	97.58	98.69	98.25	
2031	98.83	98.33	96.70	100.05	110.63	103.81	100.25	101.19	101.40	99.20	100.32	99.88	
2032	100.47	99.96	98.30	101.71	112.47	105.53	101.91	102.87	103.08		100.52	102.08	
2033	102.68	102.16	100.47	103.95	114.95	107.86	104.16	105.14	105.36	101.38	104.51	104.05	
2034	104.66	104.13	102.41	105.96	117.16	109.94	106.16	107.16	107.38	103.34	104.51	106.06	
2035	106.68	106.15	104.39	108.01	119.43	112.06	108.21	109.23	109.46	105.34		100.00	
2036	108.44	107.90	106.11	109.79	121.40	113.91	110.00	111.04	111.27	107.08	108.29 110.68	110.19	
2037	110.84	110.28	108.46	112.21	124.08	116.43	112.43	113.49	113.73	109.44	112.82	112.32	
2038	112.98	112.41	110.55	114.38	126.47	118.68	114.60	115.68	115.92	111.55		114.49	
2039	115.16	114.58	112.68	116.59	128.92	120.97	116.81	117.91	118.16	113.71	115.00		
2040	117.06	116.47	114.54	118.51	131.04	122.96	118.74	119.86	120.11	115.58	116.89	116.37	
2041	119.65	119.05	117.07	121.13	133.94	125.68	121.37	122.51	122.76	118.14	119.48	118.95	

Renewable Fixed Price Option (Continues)																
TABLE 6b Renewable Avoided Costs Renewable Avoided Costs																
LI Fixed Price Option for Columnia																
Renewable Fixed Frice Open Off-Peak Forecast (\$/MWH)																
Oct Nov									Dec							
						May	Jun		Jul	Au	3	Sep 21.11	21.36	23.	·	26.86
Year	Jan	Feb	Mar		· · · · · · ·	6.46	10.26		5.86	21		25.61	24.86	25.	~	28.11
Year 2016	25.76	20.86	14.11		1.56 5.86	13.86	12.86		9.86		.36	27.08	25.50	28.		30.77
2017	25.86	24.36	22.36	+	19.61	14.83	12.69		19.86		19	29.71	28.83			32.63
2018	26.32	28.27	25.71		18.31	15.97	14.80		22.99		.42	62.52	63.74	74 63.55		63.99
2019	30.00	28.25	25.91		63.31	59.92	60.10		60.45		1.61 2.62	63.78	65.82 63.38			65.09
2020	62.76	63.02	64.56		64.48	61.58	61.6		62.27		3.35	65.00	67.04 64.4			66.29
2021	64.93	64.15	65.8		65.49	62.45	62.8		64.33		4.85	66.14	68.41 65.			67.63 68.05
2022	65.85	65.52			67.28	62.84	64.0		65.40		5.12	66.62	62 68.68 67		7.42	69.06
2023	66.70	66.75			67.09	63.18	65.9		64.75 66.12		7.12	67.23	70.19			69.89
2024	67.25				68.08	63.17	66.2		67.05	_	37.75	67.05	71.12	`——	9.85 0.67	71.1
2025	68.62				68.56	1 00.00		22	68.79	-	101		73.22	0.22		73.4
2026	68.95				70.34	63.69		45	70.15		68.82	70.20			71.48	74.6
2027	71.31				72,10 63				71.3		70.00	71.53			73.61 75.36	76.2
2028	72.28				73.50	58.25		_	72.0		72.19	72.00			75.30 77.07	76.3
2029	72.7				73.64	58.00	<u> </u>	.89).67	73.5	5 73.71 72.16 7				78.34	77.	
2030	73.9			40	74.00			.83	74.7		74.93 73.				80.07	79.
2031	75.5			.71	75.23			3.42	76.4		76.58				81.62	
2032	76.7			.50	76.89			4.84	77.8	89 78.06		76.4			83.19	
2033	_ 1 7 _ (10-1		.09	78.37			6.28		9.39 79.5					84.57	
2034				5.71	79.8			1		70 80.88					86.44	
2035			17 8	7.13	81.2					.49 82.6				30	88.1	1 87
2036			.03 8	9.05			6.36 79. 7.64 80.				84.2			00		1 88
203			7.69 90				,, . · · · · · · · · · · · · · · · · · ·		34 85.70		85.8	~		10 0		9 90
203	07		89.38 92						70 87.12		87.3			03		1 9:
203).85	4.05				85.5			89.	24 87	.00_1_00			
204		.42 9	2.86	96.13	89.	09 1 1										
204	<u> </u>															

WIND INTEGRATION

TABLE 7										
Wind Integration Vear Cost										
Year	1001									
2015										
2016		3.84								
2017		3.91								
2018		3.99								
2019		4.07								
2020		4.15								
2021		4.23								
2022		4.31								
2023	_	4.39								
2024	_	4.47								
2025	L	4.56								
2026	\perp	4.65								
2027	\perp	4.74								
2028	_	4.83								
2029		4.92								
2030		5.02								
2031		5.12								
2032		5.21								
2033		5.31 5.42								
2034										
2035		5.52								
2036		5.63								
2037		5.74								
2038		5.85								
2039		5.96								
2040		6.08								

MONTHLY SERVICE CHARGE

Each separately metered QF not associated with a retail Customer account will be charged \$10.00 per month.

INSURANCE REQUIREMENTS

The following insurance requirements are applicable to Sellers with a Standard PPA:

- 1) QFs with nameplate capacity ratings greater than 200 kW are required to secure and maintain a prudent amount of general liability insurance. The Seller must certify to the Company that it is maintaining general liability insurance coverage for each QF at prudent amounts. A prudent amount will be deemed to mean liability insurance coverage for both bodily injury and property damage liability in the amount of not less than \$1,000,000 each occurrence combined single limit, which limits may be required to be increased or decreased by the Company as the Company determines in its reasonable judgment, that economic conditions or claims experience may warrant.
- Such insurance will include an endorsement naming the Company as an additional insured insofar as liability arising out of operations under this schedule and a provision that such liability policies will not be canceled or their limits reduced without 30 days' written notice to the Company. The Seller will furnish the Company with certificates of insurance together with the endorsements required herein. The Company will have the right to inspect the original policies of such insurance.
- 3) QFs with a design capacity of 200 kW or less are encouraged to pursue liability insurance on their own. The Oregon Public Utility Commission in Order No. 05-584 determined that it is inappropriate to require QFs that have a design capacity of 200 kW or less to obtain general liability insurance.

TRANSMISSION AGREEMENTS

If the QF is located outside the Company's service territory, the Seller is responsible for the transmission of power at its cost to the Company's service territory.

INTERCONNECTION REQUIREMENTS

Except as otherwise provided in a generation Interconnection Agreement between the Company and Seller, if the QF is located within the Company's service territory, switching equipment capable of isolating the QF from the Company's system will be accessible to the Company at all times. At the Company's option, the Company may operate the switching equipment described above if, in the sole opinion of the Company, continued operation of the QF in connection with the utility's system may create or contribute to a system emergency.

INTERCONNECTION REQUIREMENTS (Continued)

The QF owner interconnecting with the Company's distribution system must comply with all requirements for interconnection as established pursuant to Commission rule, in the Company's Rules and Regulations (Rule C) or the Company's Interconnection Procedures contained in its FERC Open Access Transmission Tariff (OATT), as applicable. The Seller will bear full responsibility for the installation and safe operation of the interconnection facilities.

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE PRICING UNDER THE STANDARD PPA

A QF will be eligible to receive pricing under the Standard PPA if the nameplate capacity of the QF, together with any other electric generating facility using the same motive force, owned or controlled by the Same Person(s) or Affiliated Person(s), and located at the Same Site, does not exceed 10 MW. A Community-Based or Family-Owned QF is exempt from these restrictions.

Definition of Community-Based

- a. A community project (or a community sponsored project) must have a recognized and established organization located within the county of the project or within 50 miles of the project that has a genuine role in helping the project be developed and must have some not insignificant continuing role with or interest in the project after it is completed and placed in service.
- b. After excluding the passive investor whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit, the equity (ownership) interests in a community sponsored project must be owned in substantial percentage (80 percent or more) by the following persons (individuals and entities): (i) the sponsoring organization, or its controlled affiliates; (ii) members of the sponsoring organization (if it is a membership organization) or owners of the sponsorship organization (if it is privately owned); (iii) persons who live in the county in which the project is located or who live a county adjoining the county in which the project is located; or (iv) units of local government, charities, or other established nonprofit organizations active either in the county in which the project is located or active in a county adjoining the county in which the project is located.

Definition of Family-Owned

After excluding the ownership interest of the passive investor whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit, five or fewer individuals own 50 percent or more of the equity of the project entity, or fifteen or fewer individuals own 90 percent or more of the project entity. A "look through" rule applies to closely held entities that hold the project entity, so that equity held by LLCs, trusts, estates, corporations, partnerships or other similar entities is considered held by the equity owners of the look through entity. An individual is a natural person. In counting to five or fifteen, spouses or children of an equity owner of the project owner who also have an equity interest are aggregated and counted as a single individual.

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE PRICING UNDER THE STANDARD PPA (Continued)

Definition of Person(s) or Affiliated Person(s)

As used above, the term "Same Person(s)" or "Affiliated Person(s)" means a natural person or persons or any legal entity or entities sharing common ownership, management or acting jointly or in concert with or exercising influence over the policies or actions of another person or entity. However, two facilities will not be held to be owned or controlled by the Same Person(s) or Affiliated Person(s) solely because they are developed by a single entity.

Furthermore, two facilities will not be held to be owned or controlled by the Same Person(s) or Affiliated Person(s) if such common person or persons is a "passive investor" whose ownership interest in the QF is primarily related to utilizing production tax credits, green tag values and MACRS depreciation as the primary ownership benefit and the facilities at issue are independent family-owned or community-based projects. A unit of Oregon local government may also be a "passive investor" in a community-based project if the local governmental unit demonstrates that it will not have an equity ownership interest in or exercise any control over the management of the QF and that its only interest is a share of the cash flow from the QF, which share will not exceed 20%. The 20% cash flow share limit may only be exceeded for good cause shown and only with the prior approval of the Commission.

Definition of Same Site

For purposes of the foregoing, generating facilities are considered to be located at the same site as the QF for which qualification for pricing under the Standard PPA is sought if they are located within a five-mile radius of any generating facilities or equipment providing fuel or motive force associated with the QF for which qualification for pricing under the Standard PPA is sought.

Definition of Shared Interconnection and Infrastructure

QFs otherwise meeting the above-described separate ownership test and thereby qualified for entitlement to pricing under the Standard PPA will not be disqualified by utilizing an interconnection or other infrastructure not providing motive force or fuel that is shared with other QFs qualifying for pricing under the Standard PPA so long as the use of the shared interconnection complies with the interconnecting utility's safety and reliability standards, interconnection agreement requirements and Prudent Electrical Practices as that term is defined in the interconnecting utility's approved Standard PPA.

OTHER DEFINITIONS

Mid-C Index Price

As used in this schedule, the daily Mid-C Index Price shall be the Day Ahead Intercontinental Exchange ("ICE") for the bilateral OTC market for energy at the Mid-C Physical for Average

OTHER DEFINITIONS (Continued)

On-Peak Power and Average Off-Peak Power found on the following website: https://www.theice.com/products/OTC/Physical-Energy/Electricity. In the event ICE no longer publishes this index, PGE and the Seller agree to select an alternative successor index representative of the Mid-C trading hub.

Definition of RPS Attributes

As used in this schedule, RPS Attributes means all attributes related to the Net Output generated by the Facility that are required in order to provide PGE with "qualifying electricity," as that term is defined in Oregon's Renewable Portfolio Standard Act, Ore. Rev. Stat. 469A.010, in effect at the time of execution of this Agreement. RPS Attributes do not include Environmental Attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity and not needed to ensure that there are zero net emissions associated with the generation of electricity.

Definition of Environmental Attributes

As used in this schedule, Environmental Attributes shall mean any and all claims, credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical, or other substance to the air, soil or water. Environmental Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil, or water such as (subject to the foregoing) sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; and (2) any avoided emissions of carbon dioxide (C02), methane (CH4), and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere.

Definition of Resource Sufficiency Period

This is the period from the current year through 2020.

Definition of Resource Deficiency Period

This is the period from 2021 through 2034.

Definition of Renewable Resource Sufficiency Period

This is the period from the current year through 2019.

Definition of Renewable Resource Deficiency Period

This is the period from 2020 through 2034.

SCHEDULE 201 (Concluded)

DISPUTE RESOLUTION

Upon request, the QF will provide the purchasing utility with documentation verifying the ownership, management and financial structure of the QF in reasonably sufficient detail to allow the utility to make an initial determination of whether or not the QF meets the above-described criteria for entitlement to pricing under the Standard PPA.

The QF may present disputes to the Commission for resolution using the following process:

The QF may file a complaint asking the Commission to adjudicate disputes regarding the formation of the standard contract. The QF may not file such a complaint during any 15-day period in which the utility has the obligation to respond, but must wait until the 15-day period has passed.

The utility may respond to the complaint within ten days of service.

The Commission will limit its review to the issues identified in the complaint and response, and utilize a process similar to the arbitration process adopted to facilitate the execution of interconnection agreements among telecommunications carriers. See OAR 860, Division 016. The administrative law judge will not act as an arbitrator.

SPECIAL CONDITIONS

- 1. Delivery of energy by Seller will be at a voltage, phase, frequency, and power factor as specified by the Company.
- 2. If the Seller also receives retail Electricity Service from the Company at the same location, any payments under this schedule will be credited to the Seller's retail Electricity Service bill. At the option of the Customer, any net credit over \$10.00 will be paid by check to the Customer.
- 3. Unless required by state or federal law, if the 1978 Public Utility Regulatory Policies Act (PURPA) is repealed, PPAs entered into pursuant to this schedule will not terminate prior to the Standard or Negotiated PPA's termination date.

TERM OF AGREEMENT

Not less than one year and not to exceed 20 years.

STANDARD RENEWABLE OFF-SYSTEM VARIABLE POWER PURCHASE

AGREEMENT

THIS AGREEMENT is between <u>Blue Marmot VIII LLC</u> ("Seller") and Portland General Electric Company ("PGE") (hereinafter each a "Party" or collectively, "Parties") and is effective upon execution by both Parties ("Effective Date").

RECITALS

Seller intends to construct, own, operate and maintain a **Solar** facility for the generation of electric power located in **Lake County, W -120.556, N 42.197** County, **Oregon** with a Nameplate Capacity Rating of **10000** kilowatt ("kW"), as further described in Exhibit A ("Facility"); and

Seller intends to operate the Facility as a "Qualifying Facility," as such term is defined in Section 3.1.3, below.

Seller shall sell and PGE shall purchase the entire Net Output, as such term is defined in Section 1.21, below, from the Facility in accordance with the terms and conditions of this Agreement.

AGREEMENT

NOW, THEREFORE, the Parties mutually agree as follows:

SECTION 1: DEFINITIONS

When used in this Agreement, the following terms shall have the following meanings:

- 1.1. "As-built Supplement" means the supplement to Exhibit A provided by Seller in accordance with Section 4.3 following completion of construction of the Facility, describing the Facility as actually built.
- 1.2. "Base Hours" is defined as the total number of hours in each Contract Year (8,760 or 8,784 for leap year)
- 1.3. "Billing Period" means from the start of the first day of each calendar month to the end of the last day of each calendar month.
- 1.4. "Cash Escrow" means an agreement by two parties to place money into the custody of a third party for delivery to a grantee only after the fulfillment of the conditions specified.
- 1.5. "Commercial Operation Date" means the date that the Facility is deemed by PGE to be fully operational and reliable. PGE may, at its discretion require, among other things, that all of the following events have occurred:
- 1.5.1. (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from a Licensed

Professional Engineer ("LPE") acceptable to PGE in its reasonable judgment stating that the Facility is able to generate electric power reliably in accordance with the terms and conditions of this Agreement (certifications required under this Section 1.5 can be provided by one or more LPEs);

- 1.5.2. Start-Up Testing of the Facility has been completed in accordance with Section 1.36;
- 1.5.3. (facilities with nameplate under 500 kW exempt from following requirement) After PGE has received notice of completion of Start-Up Testing, PGE has received a certificate addressed to PGE from an LPE stating that the Facility has operated for testing purposes under this Agreement and was continuously mechanically available for operation for a minimum of 120 hours. The Facility must provide ten (10) working days written notice to PGE prior to the start of the initial testing period. If the mechanical availability of the Facility is interrupted during this initial testing period or any subsequent testing period, the Facility shall promptly start a new Test Period and provide PGE forty-eight (48) hours written notice prior to the start of such testing period;
- 1.5.4. (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from an LPE stating that all required interconnection facilities have been constructed and all required interconnection tests have been completed;
- 1.5.5. (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from an LPE stating that Seller has obtained all Required Facility Documents and, if requested by PGE in writing, has provided copies of any or all such requested Required Facility Documents;
- 1.5.6. PGE has received a copy of the executed Generation Interconnection and Transmission Agreements.
- 1.6. "Contract Price" means the applicable price, including on-peak and offpeak prices, as specified in the Schedule.
- 1.7. "Contract Year" means each twelve (12) month period commencing upon the Commercial Operation Date or its anniversary during the Term, except the final Contract Year will be the period from the last anniversary of the Commercial Operation Date during the Term until the end of the Term.
 - 1.8. "Effective Date" has the meaning set forth in Section 2.1.
- 1.9. "Environmental Attributes" shall mean any and all claims, credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical or other substance to the air, soil or water. Environmental Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil or water such as (subject to the foregoing) sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; and (2) any avoided emissions of carbon dioxide (CO2), methane (CH4), and other greenhouse gasses (GHGs) that have been determined by the United Nations

Intergovernmental Panel on Climate Change to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere.

- 1.10. "Facility" has the meaning set forth in the Recitals.
- 1.11. "Generation Interconnection Agreement" means an agreement governing the interconnection of the Facility with PacifiCorp electric system.
- 1.12. "Generation Unit" means each separate electrical generator that contributes toward Nameplate Capacity Rating included in Exhibit A. For solar facilities, a generating unit is a complete solar electrical generation system within the Facility that is able to generate and deliver energy to the Point of Delivery independent of other Generation Units within the same Facility.
- 1.13. "Letter of Credit" means an engagement by a bank or other person made at the request of a customer that the issuer will honor drafts or other demands for payment upon compliance with the conditions specified in the letter of credit.
- 1.14. "Licensed Professional Engineer" or "LPE" means a person who is licensed to practice engineering in the state where the Facility is located, who has no economic relationship, association, or nexus with the Seller, and who is not a representative of a consulting engineer, contractor, designer or other individual involved in the development of the Facility, or of a manufacturer or supplier of any equipment installed in the Facility. Such Licensed Professional Engineer shall be licensed in an appropriate engineering discipline for the required certification being made and be acceptable to PGE in its reasonable judgment.
- 1.15. "Lost Energy" means "Lost Energy" means ((the Guarantee of Mechanical Availability as set forth in 3.1.10 / MAP) X Net Output for a Calendar Year) Net Output for the Calendar Year. Lost Energy shall be zero unless the result of the calculation in this subsection results in a positive number.
- 1.16. "Lost Energy Value" means Lost Energy X the excess of the annual time-weighted average Mid-C Index Price for On Peak Hours and Off Peak Hours over the time weighted average Contract Price for On Peak and Off Peak Hours for the corresponding time period (provided that such excess shall not exceed the Contract Price and further provided that Lost Energy is deemed to be zero prior to reaching the Commercial Operation Date) plus any reasonable costs incurred by PGE to purchase replacement power and/or transmission to deliver the replacement power to the Point of Delivery (For Start-Up Lost Energy Value See 1.35).
- 1.17. "Mechanical Availability Percentage" or "MAP" shall mean that percentage for any Contract Year for the Facility calculated in accordance with the following formula:

MAP = 100 X (Operational Hours) /(Base Hours X Number of Units)

1.18. "Mid-C Index Price" means the Day Ahead Intercontinental Exchange ("ICE") index price for the bilateral OTC market for energy at the Mid-C Physical for Average On Peak Power and Average Off Peak Power found on the following website:

https://www.theice.com/products/OTC/Physical-Energy/Electricity. In the event ICE no longer publishes this index, PGE and the Seller agree to select an alternative successor index representative of the Mid-C trading hub.

- 1.19. "Nameplate Capacity Rating" means the maximum capacity of the Facility as stated by the manufacturer, expressed in kW, which shall not exceed 10,000 kW.
- 1.20. "Net Dependable Capacity" means the maximum capacity the Facility can sustain over a specified period modified for seasonal limitations, if any, and reduced by the capacity required for station service or auxiliaries.
- 1.21. "Net Output" means all energy expressed in kWhs produced by the Facility, less station and other onsite use and less transformation and transmission losses.
- 1.22. "Number of Units" means the number of Generation Units in the Facility as specified in Exhibit A.
 - 1.23. "Off-Peak Hours" has the meaning provided in the Schedule.
 - 1.24. "On-Peak Hours" has the meaning provided in the Schedule.
- 1.25. "Operational Hours" for the Facility means the total across all Generation Units of the number of hours each of the Facility's Generation Units are potentially capable of producing power at its Nameplate Capacity Rating regardless of actual weather conditions, season and the time of day or night, without any mechanical operating constraint or restriction, and potentially capable of delivering such power to the Point of Delivery in a Contract Year. During up to, but not more than, two hundred (200) hours of Planned Maintenance during a Contract Year for each Generation Unit and hours during which an event of Force Majeure exists, a Generation Unit shall be considered potentially capable of delivering such power to the Point of Delivery. For example, in the absence of any Planned Maintenance beyond 200 hours on any Generation Unit or Event of Force Majeure, the Operational Hours for a wind farm with five (5) separate two (2) MW turbines would be 43,800 for a Contract Year.
- 1.26. "Planned Maintenance" means outages scheduled ninety (90) days in advance, with PGE's prior written consent, which shall not be unreasonably withheld.
 - 1.27. "Point of Delivery" means the PGE system.
- 1.28. "Pre-Commercial Operation Date Minimum Net Output" shall mean, unless such MWh is specifically set forth by Seller in Exhibit A, an amount in MWh equal to seventy-five percent (75%) of Nameplate Capacity Rating X thirty percent (30%) for a wind or other renewable QF or fifty percent (50%) for a solar QF X (whole months since the date selected in Section 2.2.1 / 12) X (8760 hours 200 hours (assumed Planned Maintenance)) for each month. If Seller has provided specific expected monthly Net Output amounts for the Facility in Exhibit A, "Pre-Commercial Operation Date Minimum Net Output" shall mean seventy-five percent (75%) X expected net output set forth in Exhibit A for each month.

- 1.29. "Prime Rate" means the publicly announced prime rate or reference rate for commercial loans to large businesses with the highest credit rating in the United States in effect from time to time quoted by Citibank, N.A. If a Citibank, N.A. prime rate is not available, the applicable Prime Rate shall be the announced prime rate or reference rate for commercial loans in effect from time to time quoted by a bank with \$10 billion or more in assets in New York City, N.Y., selected by the Party to whom interest based on the prime rate is being paid.
- 1.30. "Prudent Electrical Practices" means those practices, methods, standards and acts engaged in or approved by a significant portion of the electric power industry in the Western Electricity Coordinating Council that at the relevant time period, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with good business practices, reliability, economy, safety and expedition, and which practices, methods, standards and acts reflect due regard for operation and maintenance standards recommended by applicable equipment suppliers and manufacturers, operational limits, and all applicable laws and regulations. Prudent Electrical Practices are not intended to be limited to the optimum practice, method, standard or act to the exclusion of all others, but rather to those practices, methods and acts generally acceptable or approved by a significant portion of the electric power generation industry in the relevant region, during the relevant period, as described in the immediate preceding sentence.
- 1.31. "Required Facility Documents" means all licenses, permits, authorizations, and agreements necessary for construction, operation, interconnection, and maintenance of the Facility including without limitation those set forth in Exhibit B.
- 1.32. "RPS Attributes" means all attributes related to the Net Output generated by the Facility that are required in order to provide PGE with "qualifying electricity," as that term is defined in Oregon's Renewable Portfolio Standard Act, Ore. Rev. Stat. 469A.010, in effect at the time of execution of this Agreement. RPS Attributes do not include Environmental Attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity and not needed to ensure that there are zero net emissions associated with the generation of electricity.
- 1.33. "Schedule" shall mean PGE Schedule 201 filed with the Oregon Public Utilities Commission ("Commission") in effect on the Effective Date of this Agreement and attached hereto as Exhibit D, the terms of which are hereby incorporated by reference.
- 1.34. "Senior Lien" means a prior lien which has precedence as to the property under the lien over another lien or encumbrance
- 1.35. "Start-Up Lost Energy Value" means for the period after the date specified in Section 2.2.2 but prior to achievement of the Commercial Operation Date: zero, unless the Net Output is less than the pro-rated Pre-Commercial Operation Date Minimum Net Output for the applicable delay period, and the time-weighted average of the delay period's Mid-C Index Price for On-Peak Hours and Off-Peak Hours is greater

than the time-weighted average of the delay period's Contract Price for On-Peak Hours and Off-Peak Hours, in which case Startup Lost Energy Value equals: (pro-rated Pre-Commercial Operation Date Minimum Net Output for the applicable period - Net Output for the applicable period) X (the lower of: the time-weighted average of the Contract Price for On-Peak hours and Off-Peak Hours during the applicable period; or (the time-weighted average of the Mid-C Index Price for On-Peak Hours and Off-Peak Hours during the applicable period – the time-weighted average of the Contract Price for On-Peak Hours and Off-Peak Hours during the applicable period)). The time-weighted average in this section will reflect the relative proportions of On-Peak Hours and Off-Peak Hours in each day.

- 1.36. "Start-Up Testing" means the completion of applicable required factory and start-up tests as set forth in Exhibit C.
- 1.37. "Step-in Rights" means the right of one party to assume an intervening position to satisfy all terms of an agreement in the event the other party fails to perform its obligations under the agreement.
- 1.38. "Term" shall mean the period beginning on the Effective Date and ending on the Termination Date.
- 1.39. "Test Period" shall mean a period of sixty (60) days or a commercially reasonable period determined by the Seller.
- 1.40. "Transmission Agreement" means an agreement executed by the Seller and the Transmission Provider(s) for Transmission Services.
- 1.41. "Transmission Curtailment" means a limitation on Seller's ability to deliver any portion of the scheduled energy to PGE due to the unavailability of transmission to the Point of Delivery (for any reason other than Force Majeure).
- 1.42. "Transmission Curtailment Replacement Energy Cost" means the greater of zero or the amount calculated as: ((Mid-C Index Price Contract Price) X curtailed energy) for periods of Transmission Curtailment.
- 1.43. "Transmission Provider(s)" means the signatory (other than the Seller) to the Transmission Agreement.
- 1.44. "Transmission Services" means any and all services (including but not limited to ancillary services and control area services) required for the firm transmission and delivery of Energy from the Facility to the Point of Delivery for a term not less than the Term of this Agreement.

References to Recitals, Sections, and Exhibits are to be the recitals, sections and exhibits of this Agreement.

SECTION 2: TERM; COMMERCIAL OPERATION DATE

2.1. This Agreement shall become effective upon execution by both Parties ("Effective Date").

- 2.2. Time is of the essence of this Agreement, and Seller's ability to meet certain requirements prior to the Commercial Operation Date and to complete all requirements to establish the Commercial Operation Date is critically important. Therefore,
 - 2.2.1. By March 1, 2020 Seller shall begin initial deliveries of Net Output; and
- 2.2.2. By March 31, 2020 Seller shall have completed all requirements under Section 1.5 and shall have established the Commercial Operation Date.
- 2.2.3. Unless the Parties agree in writing that a later Commercial Operation Date is reasonable and necessary, the Commercial Operation Date shall be no more than three (3) years from the Effective Date. PGE will not unreasonably withhold agreement to a Commercial Operation Date that is more than three (3) years from the Effective date if the Seller has demonstrated that a later Commercial Operation Date is reasonable and necessary.
- 2.3. This Agreement shall terminate on <u>date 18 years after effective date</u>, or the date the Agreement is terminated in accordance with Section 8 or 11, whichever is earlier ("Termination Date").

SECTION 3: REPRESENTATIONS AND WARRANTIES

- 3.1. Seller and PGE represent, covenant, and warrant as follows:
- 3.1.1. Seller warrants it is a <u>Limited liability company</u> duly organized under the laws of **Delaware**.
- 3.1.2. Seller warrants that the execution and delivery of this Agreement does not contravene any provision of, or constitute a default under, any indenture, mortgage, or other material agreement binding on Seller or any valid order of any court, or any regulatory agency or other body having authority to which Seller is subject.
- 3.1.3. Seller warrants that the Facility is and shall for the Term of this Agreement continue to be a "Qualifying Facility" ("QF") as that term is defined in the version of 18 C.F.R. Part 292 in effect on the Effective Date. Seller has provided the appropriate QF certification, which may include a Federal Energy Regulatory Commission ("FERC") self-certification to PGE prior to PGE's execution of this Agreement. At any time during the Term of this Agreement, PGE may require Seller to provide PGE with evidence satisfactory to PGE in its reasonable discretion that the Facility continues to qualify as a QF under all applicable requirements.
- 3.1.4. Seller warrants that it has not within the past two (2) years been the debtor in any bankruptcy proceeding, and Seller is and will continue to be for the Term of this Agreement current on all of its financial obligations.
- 3.1.5. Seller warrants that during the Term of this Agreement, all of Seller's right, title and interest in and to the Facility shall be free and clear of all liens and encumbrances other than liens and encumbrances arising from third-party financing of the Facility other than workers', mechanics', suppliers' or similar liens, or tax liens, in each case arising in the ordinary course of business that are either not yet due and

payable or that have been released by means of a performance bond acceptable to PGE posted within eight (8) calendar days of the commencement of any proceeding to foreclose the lien.

- 3.1.6. Seller warrants that it will design and operate the Facility consistent with Prudent Electrical Practices.
- 3.1.7. Seller warrants that the Facility has a Nameplate Capacity Rating not greater than 10,000 kW.
 - 3.1.8. Seller warrants that Net Dependable Capacity of the Facility is 10,000 kW.
- 3.1.9. Seller estimates that the average annual Net Output to be delivered by the Facility to PGE is 21,950,953 kilowatt-hours ("kWh"), which amount PGE will include in its resource planning.
- 3.1.10. Seller represents and warrants that the Facility shall achieve the following Mechanical Availability Percentages ("Guarantee of Mechanical Availability"):
- 3.1.10.1. Ninety percent (90%) beginning in the first Contract Year and extending through the Term for the Facility, if the Facility was operational and sold electricity to PGE or another buyer prior to the Effective Date of this Agreement; or
- 3.1.10.2. Ninety percent (90%) beginning in Contract Year three and extending throughout the remainder of the Term.
- 3.1.10.3. Annually, within 90 days of the end of each Contract Year, Seller shall send to PGE a detailed written report demonstrating and providing evidence of the actual MAP for the previous Contract Year.
- 3.1.10.4. Seller's failure to meet the Guarantee of Mechanical Availability in a Calendar Year shall result in damages payable to PGE by Seller equal to the Lost Energy Value. PGE shall bill Seller for such damages in accordance with Section 7.
- 3.1.11. Seller will deliver from the Facility to PGE at the Point of Delivery Net Output not to exceed a maximum of 33,750,000 kWh of Net Output during each Contract Year ("Maximum Net Output"). The cost of delivering energy from the Facility to PGE is the sole responsibility of the Seller.
- 3.1.12. By the Commercial Operation Date, Seller has entered into a Generation Interconnection Agreement for a term not less than the term of this Agreement.
- 3.1.13. PGE warrants that it has not within the past two (2) years been the debtor in any bankruptcy proceeding, and PGE is and will continue to be for the Term of this Agreement current on all of its financial obligations.
- 3.1.14. Seller warrants that the Facility satisfies the eligibility requirements specified in the Definition of a Small Cogeneration Facility or Small Power Production Facility Eligible to Receive the Standard Renewable Rates and Standard Renewable PPA in PGE's Schedule and Seller will not make any changes in its ownership, control or management during the term of this Agreement that would cause it to not be in compliance with the Definition of a Small Cogeneration Facility or Small Power

Production Facility Eligible to Receive the Standard Renewable Rates and Standard Renewable PPA in PGE's Schedule. Seller will provide, upon request by PGE not more frequently than every 36 months, such documentation and information as may be reasonably required to establish Seller's continued compliance with such Definition. PGE agrees to take reasonable steps to maintain the confidentiality of any portion of the above described documentation and information that the Seller identifies as confidential except PGE will provide all such confidential information to the Commission upon the Commission's request.

3.1.15. Seller warrants that it will comply with all requirements necessary for all Transferred RECs (as defined in Section 4.5) associated with Net Output to be issued, monitored, accounted for, and transferred by and through the Western Renewable Energy Generation System consistent with the provisions of OAR 330-160-0005 through OAR 330-160-0050. PGE warrants that it will reasonably cooperate in Seller's efforts to meet such requirements, including, for example serving as the qualified reporting entity for the Facility if the Facility is located in PGE's balancing authority.

SECTION 4: DELIVERY OF POWER, PRICE AND ENVIRONMENTAL ATTRIBUTES

- 4.1. Commencing on the Effective Date and continuing through the Term of this Agreement, Seller shall sell to PGE the entire Net Output delivered from the Facility at the Point of Delivery.
 - 4.2. PGE shall pay Seller the Contract Price for all delivered Net Output.
- 4.3. Upon completion of construction of the Facility, Seller shall provide PGE an As-built Supplement to specify the actual Facility as built. Seller shall not increase the Nameplate Capacity Rating above that specified in Exhibit A or increase the ability of the Facility to deliver Net Output in quantities in excess of the Net Dependable Capacity, or the Maximum Net Output as described in Section 3.1.11 above, through any means including, but not limited to, replacement, modification, or addition of existing equipment, except with prior written notice to PGE. In the event Seller increases the Nameplate Capacity Rating of the Facility to no more than 10,000 kW pursuant to this section, PGE shall pay the Contract Price for the additional delivered Net Output. In the event Seller increases the Nameplate Capacity Rating to greater than 10,000 kW, then Seller shall be required to enter into a new power purchase agreement for all delivered Net Output proportionally related to the increase of Nameplate Capacity above 10,000 kW.
- 4.4. Seller shall provide preschedules for all deliveries of energy hereunder, including identification of receiving and generating control areas, by 9:00:00 PPT on the last business day prior to the scheduled date of delivery. All energy shall be scheduled according to the most current North America Energy Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) scheduling rules and practices. The Parties' respective representatives shall maintain hourly real-time schedule coordination; provided, however, that in the absence of such coordination, the hourly schedule established by the exchange of preschedules shall be considered final. Seller and PGE shall maintain records of hourly energy schedules for accounting and

operating purposes. The final E-Tag shall be the controlling evidence of the Parties' schedule. All energy shall be prescheduled according to customary WECC scheduling practices. Seller shall make commercially reasonable efforts to schedule in any hour an amount equal to its expected Net Output for such hour. Seller shall maintain a minimum of two years records of Net Output and shall agree to allow PGE to have access to such records and to imbalance information kept by the Transmission Provider.

From the start of the Renewable Resource Deficiency Period through the remainder of the Term of this Agreement, Seller shall provide and PGE shall acquire the RPS Attributes for the Contract Years as specified in the Schedule and Seller shall retain ownership of all other Environmental Attributes (if any). During the Renewable Resource Sufficiency Period, Seller shall retain all Environmental Attributes in accordance with the Schedule. The Contract Price includes full payment for the Net Output and any RPS Attributes transferred to PGE under this Agreement. With respect to Environmental Attributes not transferred to PGE under this Agreement ("Seller-Retained Environmental Attributes") Seller may report under §1605(b) of the Energy Policy Act of 1992 or under any applicable program as belonging to Seller any of the Seller-Retained Environmental Attributes, and PGE shall not report under such program that such Seller-Retained Environmental Attributes belong to it. With respect to RPS Attributes transferred to PGE under this Agreement ("Transferred RECs"), PGE may report under §1605(b) of the Energy Policy Act of 1992 or under any applicable program as belonging to it any of the Transferred RECs, and Seller shall not report under such program that such Transferred RECs belong to it.

SECTION 5: OPERATION AND CONTROL

- 5.1. Seller shall operate and maintain the Facility in a safe manner in accordance with the Generation Interconnection Agreement, and Prudent Electrical Practices. PGE shall have no obligation to purchase Net Output from the Facility to the extent the interconnection of the Facility to PGE's electric system is disconnected, suspended or interrupted, in whole or in part, pursuant to the Generation Interconnection Agreement, or to the extent generation curtailment is required as a result of Seller's noncompliance with the Generation Interconnection Agreement. Seller is solely responsible for the operation and maintenance of the Facility. PGE shall not, by reason of its decision to inspect or not to inspect the Facility, or by any action or inaction taken with respect to any such inspection, assume or be held responsible for any liability or occurrence arising from the operation and maintenance by Seller of the Facility.
- 5.2. Seller agrees to provide sixty (60) days advance written notice of any scheduled maintenance that would require shut down of the Facility for any period of time.
- 5.3. If the Facility ceases operation for unscheduled maintenance, Seller immediately shall notify PGE of the necessity of such unscheduled maintenance, the time when such maintenance has occurred or will occur, and the anticipated duration of such maintenance. Seller shall take all reasonable measures and exercise its best

efforts to avoid unscheduled maintenance, to limit the duration of such unscheduled maintenance, and to perform unscheduled maintenance during Off-Peak hours.

SECTION 6: CREDITWORTHINESS

In the event Seller: a) is unable to represent or warrant as required by Section 3 that it has not been a debtor in any bankruptcy proceeding within the past two (2) years; b) becomes such a debtor during the Term; or c) is not or will not be current on all its financial obligations, Seller shall immediately notify PGE and shall promptly (and in no less than 10 days after notifying PGE) provide default security in an amount reasonably acceptable to PGE in one of the following forms: Senior Lien, Step-in Rights, a Cash Escrow or Letter of Credit. The amount of such default security that shall be acceptable to PGE shall be equal to: (annual On Peak Hours) X (On Peak Price – Off Peak Price) X (Net Dependable Capacity). Notwithstanding the foregoing, in the event Seller is not current on construction related financial obligations, Seller shall notify PGE of such delinquency and PGE may, in its discretion, grant an exception to the requirements to provide default security if the QF has negotiated financial arrangements with the construction loan lender that mitigate Seller's financial risk to PGE.

SECTION 7: BILLINGS, COMPUTATIONS AND PAYMENTS

- 7.1. On or before the thirtieth (30th) day following the end of each Billing Period, PGE shall send to Seller payment for Seller's deliveries of Net Output to PGE, together with computations supporting such payment. PGE may offset any such payment to reflect amounts owing from Seller to PGE pursuant to this Agreement and any other agreement related to the Facility between the Parties or otherwise. On or before the thirtieth (30th) day following the end of each Contract Year, PGE shall bill for any Lost Energy Value accrued pursuant to this Agreement.
- 7.2. Any amounts owing after the due date thereof shall bear interest at the Prime Rate plus two percent (2%) from the date due until paid; provided, however, that the interest rate shall at no time exceed the maximum rate allowed by applicable law.

SECTION 8: DEFAULT, REMEDIES AND TERMINATION

- 8.1. In addition to any other event that may constitute a default under this Agreement, the following events shall constitute defaults under this Agreement:
- 8.1.1. Breach by Seller or PGE of a representation or warranty, except for Section 3.1.4, set forth in this Agreement.
- 8.1.2. Seller's failure to provide default security, if required by Section 6, prior to delivery of any Net Output to PGE or within 10 days of notice.
- 8.1.3. Seller's failure to meet the Guarantee of Mechanical Availability established in Section 3.1.10 for two consecutive Contract Years or Seller's failure to provide any written report required by that section.
 - 8.1.4. If Seller is no longer a Qualifying Facility.
 - 8.1.5. Failure of PGE to make any required payment pursuant to Section 7.1.

- 8.1.6. Seller's failure to meet the Commercial Operation Date.
- 8.2. In the event of a default under Section 8.1.6, PGE may provide Seller with written notice of default. Seller shall have one year in which to cure the default during which time the Seller shall pay PGE damages equal to the Lost Energy Value. If Seller is unable to cure the default, PGE may immediately terminate this Agreement as provided in Section 8.3. PGE's resource sufficiency/deficiency position shall have no bearing on PGE's right to terminate the Agreement under this Section 8.2.
- 8.3. In the event of a default hereunder, except as otherwise provided in this Agreement, the non-defaulting party may immediately terminate this Agreement at its sole discretion by delivering written notice to the other Party. In addition, the non-defaulting Party may pursue any and all legal or equitable remedies provided by law or pursuant to this Agreement including damages related to the need to procure replacement power. A termination hereunder shall be effective upon the date of delivery of notice, as provided in Section 20. The rights provided in this Section 8 are cumulative such that the exercise of one or more rights shall not constitute a waiver of any other rights.
- 8.4. If this Agreement is terminated as provided in this Section 8, PGE shall make all payments, within thirty (30) days, that, pursuant to the terms of this Agreement, are owed to Seller as of the time of receipt of notice of default. PGE shall not be required to pay Seller for any Net Output delivered by Seller after such notice of default.
- 8.5. In the event PGE terminates this Agreement pursuant to this Section 8, and Seller wishes to again sell Net Output to PGE following such termination, PGE in its sole discretion may require that Seller shall do so subject to the terms of this Agreement, including but not limited to the Contract Price until the Term of this Agreement (as set forth in Section 2.3) would have run in due course had the Agreement remained in effect. At such time Seller and PGE agree to execute a written document ratifying the terms of this Agreement.
- 8.6. Sections 8.1, 8.4, 8.5, 10, and 19.2 shall survive termination of this Agreement.

SECTION 9: TRANSMISSION CURTAILMENTS

- 9.1. Seller shall give PGE notice as soon as reasonably practicable of any Transmission Curtailment that is likely to affect Seller's ability to deliver any portion of energy scheduled pursuant to Section 4.4 of this Agreement.
- 9.2. If as the result of a Transmission Curtailment, Seller does not deliver any portion of energy (including real-time adjustments), scheduled pursuant to Section 4.4 of this Agreement, Seller shall pay PGE the Transmission Curtailment Replacement Energy Cost for the number of MWh of energy reasonably determined by PGE as the difference between (i) the scheduled energy that would have been delivered to PGE under this Agreement during the period of Transmission Curtailment and (ii) the actual energy, if any, that was delivered to PGE for the period.

SECTION 10: INDEMNIFICATION AND LIABILITY

- 10.1. Seller agrees to defend, indemnify and hold harmless PGE, its directors, officers, agents, and representatives against and from any and all loss, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with Seller's delivery of electric power to PGE or with the facilities at or prior to the Point of Delivery, or otherwise arising out of this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PGE, Seller or others, excepting to the extent such loss, claim, action or suit may be caused by the negligence of PGE, its directors, officers, employees, agents or representatives.
- 10.2. PGE agrees to defend, indemnify and hold harmless Seller, its directors, officers, agents, and representatives against and from any and all loss, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with PGE's receipt of electric power from Seller or with the facilities at or after the Point of Delivery, or otherwise arising out of this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PGE, Seller or others, excepting to the extent such loss, claim, action or suit may be caused by the negligence of Seller, its directors, officers, employees, agents or representatives.
- 10.3. Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a Party to this Agreement. No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or to the public, nor affect the status of PGE as an independent public utility corporation or Seller as an independent individual or entity.
- 10.4. NEITHER PARTY SHALL BE LIABLE TO THE OTHER FOR SPECIAL, PUNITIVE, INDIRECT OR CONSEQUENTIAL DAMAGES, WHETHER ARISING FROM CONTRACT, TORT (INCLUDING NEGLIGENCE), STRICT LIABILITY OR OTHERWISE.

SECTION 11: INSURANCE

11.1. Prior to the connection of the Facility to PGE's electric system, provided such Facility has a design capacity of 200 kW or more, Selier shall secure and continuously carry for the Term hereof, with an insurance company or companies rated not lower than "B+" by the A. M. Best Company, insurance policies for bodily injury and property damage liability. Such insurance shall include provisions or endorsements naming PGE, it directors, officers and employees as additional insureds; provisions that such insurance is primary insurance with respect to the interest of PGE and that any insurance or self-insurance maintained by PGE is excess and not contributory insurance with the insurance required hereunder; a cross-liability or severability of

insurance interest clause; and provisions that such policies shall not be canceled or their limits of liability reduced without thirty (30) days' prior written notice to PGE. Initial limits of liability for all requirements under this section shall be \$1,000,000 million single limit, which limits may be required to be increased or decreased by PGE as PGE determines in its reasonable judgment economic conditions or claims experience may warrant.

- 11.2. Prior to the connection of the Facility to PGE's electric system, provided such facility has a design capacity of 200 kW or more, Seller shall secure and continuously carry for the Term hereof, in an insurance company or companies rated not lower than "B+" by the A. M. Best Company, insurance acceptable to PGE against property damage or destruction in an amount not less than the cost of replacement of the Facility. Seller promptly shall notify PGE of any loss or damage to the Facility. Unless the Parties agree otherwise, Seller shall repair or replace the damaged or destroyed Facility, or if the facility is destroyed or substantially destroyed, it may terminate this Agreement. Such termination shall be effective upon receipt by PGE of written notice from Seller. Seller shall waive its insurers' rights of subrogation against PGE regarding Facility property losses.
- 11.3. Prior to the connection of the Facility to PGE's electric system and at all other times such insurance policies are renewed or changed, Seller shall provide PGE with a copy of each insurance policy required under this Section, certified as a true copy by an authorized representative of the issuing insurance company or, at the discretion of PGE, in lieu thereof, a certificate in a form satisfactory to PGE certifying the issuance of such insurance. If Seller fails to provide PGE with copies of such currently effective insurance policies or certificates of insurance, PGE at its sole discretion and without limitation of other remedies, may upon ten (10) days advance written notice by certified or registered mail to Seller either withhold payments due Seller until PGE has received such documents, or purchase the satisfactory insurance and offset the cost of obtaining such insurance from subsequent power purchase payments under this Agreement.

SECTION 12: FORCE MAJEURE

12.1. As used in this Agreement, "Force Majeure" or "an event of Force Majeure" means any cause beyond the reasonable control of the Seller or of PGE which, despite the exercise of due diligence, such Party is unable to prevent or overcome. By way of example, Force Majeure may include but is not limited to acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes, and other labor disturbances, earthquakes, fires, lightning, epidemics, sabotage, restraint by court order or other delay or failure in the performance as a result of any action or inaction on behalf of a public authority which by the exercise of reasonable foresight such Party could not reasonably have been expected to avoid and by the exercise of due diligence, it shall be unable to overcome, subject, in each case, to the requirements of the first sentence of this paragraph. Force Majeure, however, specifically excludes the cost or availability of resources to operate the Facility, changes in market conditions that affect

the price of energy or transmission, wind or water droughts, and obligations for the payment of money when due.

- 12.2. If either Party is rendered wholly or in part unable to perform its obligation under this Agreement because of an event of Force Majeure, that Party shall be excused from whatever performance is affected by the event of Force Majeure to the extent and for the duration of the Force Majeure, after which such Party shall recommence performance of such obligation, provided that:
- 12.2.1. the non-performing Party, shall, promptly, but in any case within one (1) week after the occurrence of the Force Majeure, give the other Party written notice describing the particulars of the occurrence; and
- 12.2.2. the suspension of performance shall be of no greater scope and of no longer duration than is required by the Force Majeure; and
- 12.2.3. the non-performing Party uses its best efforts to remedy its inability to perform its obligations under this Agreement.
- 12.3. No obligations of either Party which arose before the Force Majeure causing the suspension of performance shall be excused as a result of the Force Majeure.
- 12.4. Neither Party shall be required to settle any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to the Party's best interests.

SECTION 13: SEVERAL OBLIGATIONS

Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership or joint venture or to impose a trust or partnership duty, obligation or liability between the Parties. If Seller includes two or more parties, each such party shall be jointly and severally liable for Seller's obligations under this Agreement.

SECTION 14: CHOICE OF LAW

This Agreement shall be interpreted and enforced in accordance with the laws of the state of Oregon, excluding any choice of law rules which may direct the application of the laws of another jurisdiction.

SECTION 15: PARTIAL INVALIDITY AND PURPA REPEAL

It is not the intention of the Parties to violate any laws governing the subject matter of this Agreement. If any of the terms of the Agreement are finally held or determined to be invalid, illegal or void as being contrary to any applicable law or public policy, all other terms of the Agreement shall remain in effect. If any terms are finally held or determined to be invalid, illegal or void, the Parties shall enter into negotiations concerning the terms affected by such decision for the purpose of achieving conformity with requirements of any applicable law and the intent of the Parties to this Agreement.

In the event the Public Utility Regulatory Policies Act (PURPA) is repealed, this Agreement shall not terminate prior to the Termination Date, unless such termination is mandated by state or federal law.

SECTION 16: WAIVER

Any waiver at any time by either Party of its rights with respect to a default under this Agreement or with respect to any other matters arising in connection with this Agreement must be in writing, and such waiver shall not be deemed a waiver with respect to any subsequent default or other matter.

SECTION 17: GOVERNMENTAL JURISDICTION AND AUTHORIZATIONS

This Agreement is subject to the jurisdiction of those governmental agencies having control over either Party or this Agreement. Seller shall at all times maintain in effect all local, state and federal licenses, permits and other approvals as then may be required by law for the construction, operation and maintenance of the Facility, and shall provide upon request copies of the same to PGE.

SECTION 18: SUCCESSORS AND ASSIGNS

This Agreement and all of the terms hereof shall be binding upon and inure to the benefit of the respective successors and assigns of the Parties. No assignment hereof by either Party shall become effective without the written consent of the other Party being first obtained and such consent shall not be unreasonably withheld. Notwithstanding the foregoing, either Party may assign this Agreement without the other Party's consent as part of (a) a sale of all or substantially all of the assigning Party's assets, or (b) a merger, consolidation or other reorganization of the assigning Party.

SECTION 19: ENTIRE AGREEMENT

- 19.1. This Agreement supersedes all prior agreements, proposals, representations, negotiations, discussions or letters, whether oral or in writing, regarding PGE's purchase of Net Output from the Facility. No modification of this Agreement shall be effective unless it is in writing and signed by both Parties.
- 19.2. By executing this Agreement, Seller releases PGE from any third party claims related to the Facility, known or unknown, which may have arisen prior to the Effective Date.

SECTION 20: NOTICES

20.1. All notices except as otherwise provided in this Agreement shall be in writing, shall be directed as follows and shall be considered delivered if delivered in person or when deposited in the U.S. Mail, postage prepaid by certified or registered mail and return receipt requested:

To Seller:

Blue Marmot VIII LLC

c/o EDP Renewables North America LLC; Attention: General

Counsel

808 Travis, Suite 700 Houston, Texas 77002

with a copy to:

To PGE:

Contracts Manager

QF Contracts, 3WTC0306 PGE - 121 SW Salmon St. Portland, Oregon 97204

20.2 The Parties may change the person to whom such notices are addressed, or their addresses, by providing written notices thereof in accordance with this Section 20.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed in their respective names as of the Effective Date.

PGE	
Ву:	
By: Name:	
Title:	
Date:	

Blue Marmot VIII LLC

(Name Seller)

511

Name: Executive Vice President,

Title: Western and Central Regions and Mexico

Date: 4/28/17

Bernardo Goarmon Executive Vice President, Finance

EXHIBIT A DESCRIPTION OF SELLER'S FACILITY

The facility will be a solar PV plant consisting of 39,324 polycrystalline modules of nominal 335W rating each. Total plant rating will be 13.174MWdc/10MWac. Modules will be mounted to single-axis trackers.

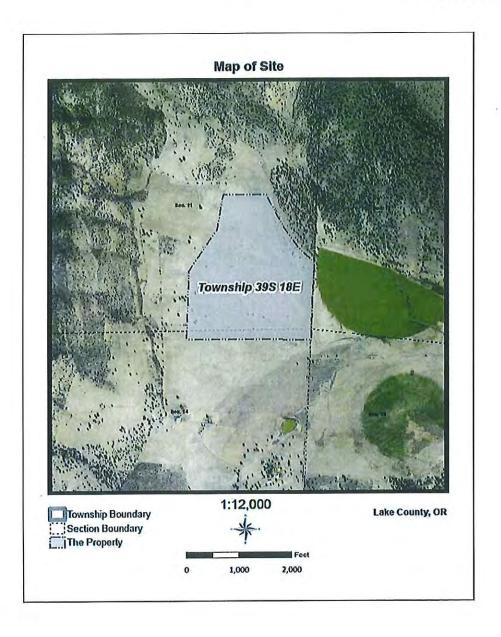
Central inverter stations will be located at intermediate points in the PV field. Modules will be evenly distributed to the inverter stations. The total inverter nameplate rating will be 10.0MWac. Each inverter will be directly coupled to a 34.5kV step-up transformer. The transformers will be connected to a 34.5kV AC collection system, which will feed into the plant switchgear.

The plant switchgear will feed a 34.5kV transmission line, which will run overhead approximately 11.1 miles to the PacifiCorp Mile-Hi Substation.

Inside the Mile-Hi Substation, the transmission line will connect to a new bay containing a facility-owned 34.5kV/115kV GSU transformer, associated breakers, switching, bus, and controls.

The facility-owned components at Mile-Hi substation are considered part of the self-certified qualifying facility.

Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016



See tab "Generation"

N/A

Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

Note this information is considered representative design information which is to be updated at the time of project Solar Facility Characteristics: construction and is subject to design finalization 1. Generation a. PVSyst (or equivalent) simulation results detail, including but not limited to: 23,931 i. Annual MWh (AC) for the first calendar year of commercial operation 0.50% II. Annual degradation factor See tab "Generation" lii. Average 24-hr profile of generation MWh (AC) for each month during the first calendar 27% Iv. Expected Solar Capacity Factor See tab "Generation" v. Maximum annual output (monthly MWh detail)

2. Description of Modules: Polycrystalline Silicon a. Module type 39, 324 b. # of modules 37,4V c. Max power voltage 8.97A d. Max power current

e. Max system voltage f. Total DC system size

3. Description of Racking

a. Racking 1. Type: (fixed tilt, single-axis tracking, or dual-axis tracking, etc.)

II. Tilt angle (if fixed-tilt) III. Azimuth (default = south-facing)

4. Description of Inverters:

Iv. Loss Diagram

a. Number of Inverters

h. Model c. Maximum Power (kW)

d. Operating Voltage (VAC)

e. Max. Output Current (A)

f. Rated DC Voltage

g. Rated DC current

h. Maximum Output (kW)

g. Facility AC Capacity Rating

h. Inverter loading ratio i. Facility AC rating

Description of transformers

Inverter LV-MV

a. # of transformers

b. Model

c. High Voltage Rating

d. Low Voltage Rating

e. MVA rating

f. High voltage connection

g. Low voltage connection

GSU MV-HV

a. If of transformers

5. Model c. High Voltage Rating

d. Low Voltage Rating

e. MVA rating

f. High voltage connection

g. Low voltage connection

6. Description of metering, communications, and monitoring

سمات سواديا تستنفه البيب سيانات وسيست وهنارا الاستفاد المسان والمالسان والمالسان والمالسان والمالسان

7. Description of station service requirements

13.174kW

Single-AxIs Tracking

South-Facing

1500V

ABB PVS980-58-1818kVA-6

2910kW DC 600 1925A

1500 1945 2000

10.0MW 1.317

10.0MW

ABB PadPlus+ 34,500

600 2.0 each, 10.0 total Wve-Ground

Wve

ABB 10MVA 115,000 34,500 10/12.5 ONAF Wye

Meter shall be revenue-grade, located at POI. POI shall be slack bus on the high-side bushing of plant GSU transformer at Mile Hi Substation. Revenue meter shall transmit real-time data pulses (instantaneous MW, MVAR, KWH) to Operator's billing data program. Customer's 35kV switchgear at Mile Hi shall be fitted with Customer meter as an alternate data source. Breakers and relays at Customer's PV plant shall connect to operator SCADA system at Mile Hi substation via OPGW run on proposed Customer transmission line. Customer shall install line-protection panel, metering equipment and accessories, communication battery system, fiber optic network device and SCADA RTU (Remote Terminal Unit) in existing Mile Hi relay/control building to control, monitor, and transmit data to Operator and back to PV plant SCADA.

15KVA, 240/120V 1-phase service at PV plant substation for Relay/SCADA/O&M building and plant accessory loads. 5KVA, 240/120V 1-phase at Mile Hi substation for Customer controls equipment.

Transmission line shall be new radial line consisting of 34.5KV ACSR, 1-conductor per phase with OPGW on wood poles, approx. 11.1 miles. Line will originate at PV plant 34.5kV main switchgear and terminate at dead-end structure feeding a new 35kV breaker at Mile Hi Substation. 35kV breaker will feed new G5U and new agricis basalian sa kesta 116 riibakaktan 1979 ahabi ba afaafi bira

20

EXHIBIT B REQUIRED FACILITY DOCUMENTS

Sellers Generation Interconnection Agreement

Transmission Service Agreement with PacifiCorp

Lease agreement

Conditional Use Permit issued by Lake County

Any additional permits that might be required by Lake County or Oregon Department of Environmental Quality, including access permit, building and electric permits, and storm water prevention permit

FERC Qualifying Facility self-certification

EXHIBIT C START-UP TESTING

VISUAL AND MECHANICAL INSPECTIONS

INVERTER COMMISSIONING

ELECTRICAL OPERATION TESTS

SYSTEM MONITORING VERIFICATION

TRACKER VERIFICATION

INFRARED SCANS

BLOCK TESTING

72-HOUR FUNCTIONAL TEST

GRID MATCH TEST

POWER CHARACTERIZATION

REVENUE METER VERIFICATION

REACTIVE POWER TEST

POWER OUTPUT TEST - PLANT PERFORMANCE AND ACCEPTANCE

Blue Marmot/202 Talbott/220

Schedule 201 Standard Renewable Off-System Variable Power Purchase Agreement Form Effective August 12, 2016

> EXHIBIT D SCHEDULE

SCHEDULE 201 QUALIFYING FACILITY 10 MW or LESS AVOIDED COST POWER PURCHASE INFORMATION

PURPOSE

To provide information about Standard Avoided Costs and Renewable Avoided Costs, Standard Power Purchase Agreements (PPA) and Negotiated PPAs, power purchase prices and price options for power delivered by a Qualifying Facility (QF) to the Company with nameplate capacity of 10,000 kW (10MW) or less.

AVAILABLE

To owners of QFs making sales of electricity to the Company in the State of Oregon (Seller).

APPLICABLE

For power purchased from small power production or cogeneration facilities that are QFs as defined in 18 Code of Federal Regulations (CFR) Section 292, that meet the eligibility requirements described herein and where the energy is delivered to the Company's system and made available for Company purchase pursuant to a Standard PPA.

ESTABLISHING CREDITWORTHINESS

The Seller must establish creditworthiness prior to service under this schedule. For a Standard PPA, a Seller may establish creditworthiness with a written acknowledgment that it is current on all existing debt obligations and that it was not a debtor in a bankruptcy proceeding within the preceding 24 months. If the Seller is not able to establish creditworthiness, the Seller must provide security deemed sufficient by the Company as set forth in the Standard PPA.

POWER PURCHASE INFORMATION

A Seller may call the Power Production Coordinator at (503) 464-8000 to obtain more information about being a Seller or how to apply for service under this schedule.

PPA

In accordance with terms set forth in this schedule and the Commission's Rules as applicable, the Company will purchase any Energy in excess of station service (power necessary to produce generation) and amounts attributable to conversion losses, which are made available from the Seller.

A Seller must execute a PPA with the Company prior to delivery of power to the Company. The agreement will have a term of up to 20 years as selected by the QF.

A QF with a nameplate capacity rating of 10 MW or less as defined herein may elect the option of a Standard PPA.

PPA (Continued)

Any Seller may elect to negotiate a PPA with the Company. Such negotiation will comply with the requirements of the Federal Energy Regulatory Commission (FERC), and the Commission including the guidelines in Order No. 07-360, and Schedule 202. Negotiations for power purchase pricing will be based on either the filed Standard Avoided Costs or Renewable Avoided Costs in effect at that time.

STANDARD PPA (Nameplate capacity of 10 MW or less)

A Seller choosing a Standard PPA will complete all informational and price option selection requirements in the applicable Standard PPA and submit the executed Agreement to the Company prior to service under this schedule. The Standard PPA is available at www.portlandgeneral.com. The available Standard PPAs are:

- Standard In-System Non-Variable Power Purchase Agreement
- Standard Off-System Non-Variable Power Purchase Agreement
- Standard In-System Variable Power Purchase Agreement
- Standard Off-System Variable Power Purchase Agreement
- Standard Renewable In-System Non-Variable Power Purchase Agreement
- Standard Renewable Off-System Non-Variable Power Purchase Agreement
- Standard Renewable In-System Variable Power Purchase Agreement
- Standard Renewable Off-System Variable Power Purchase Agreement

The Standard PPAs applicable to variable resources are available only to QFs utilizing wind, solar or run of river hydro as the primary motive force.

GUIDELINES FOR 10 MW OR LESS FACILITIES ELECTING STANDARD PPA

To execute the Standard PPA the Seller must complete all of the general project information requested in the applicable Standard PPA.

When all information required in the Standard PPA has been received in writing from the Seller, the Company will respond within 15 business days with a draft Standard PPA.

The Seller may request in writing that the Company prepare a final draft Standard PPA. The Company will respond to this request within 15 business days. In connection with such request, the QF must provide the Company with any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft Standard PPA.

When both parties are in full agreement as to all terms and conditions of the draft Standard PPA, the Company will prepare and forward to the Seller a final executable version of the agreement within 15 business days. Following the Company's execution, an executed copy will be returned to the Seller. Prices and other terms and conditions in the PPA will not be final and binding until the Standard PPA has been executed by both parties.

OFF-SYSTEM PPA

A Seller with a facility that interconnects with an electric system other than the Company's electric system may enter into a PPA with the Company after following the applicable Standard or Negotiated PPA guidelines and making the arrangements necessary for transmission of power to the Company's system.

BASIS FOR POWER PURCHASE PRICE

AVOIDED COST SUMMARY

The power purchase prices are based on either the Company's Standard Avoided Costs or Renewable Avoided Costs in effect at the time the agreement is executed. Avoided Costs are defined in 18 CFR 292.101(6) as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."

Monthly On-Peak prices are included in both the Standard Avoided Costs as listed in Tables 1a, 2a, and 3a and Renewable Avoided Costs as listed in Tables 4a, 5a, and 6a. Monthly Off-Peak prices are included in both the Standard Avoided Costs as listed in Tables 1b, 2b, and 3b and Renewable Avoided Costs as listed in Tables 4b, 5b, and 6b.

ON-PEAK PERIOD

The On-Peak period is 6:00 a.m. until 10:00 p.m., Monday through Saturday.

OFF-PEAK PERIOD

The Off-Peak period is 10:00 p.m. until 6:00 a.m., Monday through Saturday, and all day on Sunday.

Standard Avoided Costs are based on forward market price estimates through the Resource Sufficiency Period, the period of time during which the Company's Standard Avoided Costs are associated with incremental purchases of Energy and capacity from the market. For the Resource Deficiency Period, the Standard Avoided Costs reflect the fully allocated costs of a natural gas fueled combined cycle combustion turbine (CCCT) including fuel and capital costs. The CCCT Avoided Costs are based on the variable cost of Energy plus capitalized Energy costs at a 93% capacity factor based on a natural gas price forecast, with prices modified for shrinkage and transportation costs.

Renewable Avoided Costs are based on forward market price estimates through the Renewable Resource Sufficiency Period, the period of time during which the Company's Renewable Avoided Costs are associated with incremental purchases of energy and capacity from the market. For the Renewable Resource Deficiency Period, the Renewable Avoided Costs reflect the fully allocated costs of a wind plant including capital costs.

Sheet No. 201-4

SCHEDULE 201 (Continued)

PRICING FOR STANDARD PPA

Pricing represents the purchase price per MWh the Company will pay for electricity delivered to a Point of Delivery (POD) within the Company's service territory pursuant to a Standard PPA up to the nameplate rating of the QF in any hour. Any Energy delivered in excess of the nameplate rating will be purchased at the applicable Off-Peak Prices for the selected pricing option.

The Standard PPA pricing will be based on either the Standard or Renewable Avoided Costs in effect at the time the agreement is executed.

The Company will pay the Seller either the Off-Peak Standard Avoided Cost pursuant to Tables 1b, 2b, or 3b or the Off-Peak Renewable Avoided Costs pursuant to Tables 4b, 5b, or 6b for: (a) all Net Output delivered prior to the Commercial Operation Date; (b) all Net Output deliveries greater than Maximum Net Output in any PPA year; (c) any generation subject to and as adjusted by the provisions of Section 4.3 of the Standard PPA; (d) Net Output delivered in the Off-Peak Period; and (e) deliveries above the nameplate capacity in any hour. The Company will pay the Seller either the On-Peak Standard Avoided Cost pursuant to Tables 1a, 2a, or 3a or the On-Peak Renewable Avoided Costs pursuant to Tables 4a, 5a, or 6a for all other Net Output. (See the PPA for defined terms.)

1) Standard Fixed Price Option

The Standard Fixed Price Option is based on Standard Avoided Costs including forecasted natural gas prices. It is available to all QFs.

This option is available for a maximum term of 15 years. Prices will be as established at the time the Standard PPA is executed and will be equal to the Standard Avoided Costs in Tables 1a and 1b, 2a and 2b, or 3a and 3c, depending on the type of QF, effective at execution. QFs using any resource type other than wind and solar are assumed to be Base Load QFs.

Prices paid to the Seller under the Standard Fixed Price Option include adjustments for the capacity contribution of the QF resource type relative to that of the avoided proxy resource. Both the Base Load QF resources (Tables 1a and 1b) and the avoided proxy resource, the basis used to determine Standard Avoided Costs for the Standard Fixed Price Option, are assumed to have a capacity contribution to peak of 100%. The capacity contribution for Wind QF resources (Tables 2a and 2b) is assumed to be 5%. The capacity contribution for Solar QF resources (Tables 3a and 3b) is assumed to be 5%.

Prices paid to the Seller under the Standard Fixed Price Option for Wind QFs (Tables 2a and 2b) include a reduction for the wind integration costs in Table 7. However, if the Wind QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the wind integration charges in Table 7, in addition to the prices listed in Tables 2a and 2b, for a net-zero effect.

Sheet No. 201-5

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

Sellers with PPAs exceeding 15 years will receive pricing equal to the Mid-C Index Price for all years up to five in excess of the initial 15.

					T.	ABLE 1a						
					Avo	ided Cos	ts					
			St	andard F	ixed Pric	e Option	for Base	Load QF				
				0	n-Peak F	orecast (\$/MWH)				•	
Year	Jan	Feb	Mar	Apr	May	Jun	<u>Jul</u>	Aug	Sep	Oct	Nov	Dec
2016	28.21	22.46	15.61	14.71	12.46	16.96	23.96	26.96	24.96	23.71	26.71	31,46
2017	29,96	28.21	24.71	20.96	19.46	20.46	27.96	30.96	29.46	27.71	28.71	33.71
2018	31.71	31.11	28.11	22.13	21.28	21.28	29,93	33.37	30.63	28.61	31.86	35.71
2019	33.94	31.95	27.97	23.70	22.00	23.13	31.67	35,08	33.37	31.38	32.52	38.21
2020	35.74	33.64	29.45	24.95	23.15	24.35	33,34	36.94	35,14	33.04	34.24	40.24
2021	67.43	67.34	65.41	64.69	64.41	64.50	64.61	64.73	64.84	65.48	68,60	68,72
2022	69.01	68.84	68.08	67.13	66.81	66.91	67.04	67.17	67.29	67.83	71.38	71.70
2023	71.95	71.76	70.39	69.19	69.07	69.18	69.31	69,45	69.58	70.12	73.56	73.70
2024	74.17	73.85	72.67	71.29	71.10	71.21	71.35	71.50	71.63	72.20	76.49	76.64
2025	77.19	77.30	75.84	74.88	75.02	75.14	75.30	75.47	75.62	75.80	82.57	82.89
2026	85.18	85.30	82.77	81.28	81.22	81.36	81.56	81.74	81.90	82.36	89.02	88.72
2027	86.85	86.76	85.14	83.12	82.89	83,03	83.00	83.32	83.46	83.97	91.39	91.15
2028	89.32	89.31	87.96	85.46	85.30	85.46	85.31	85,64	85.95	86.65	94.66	93.55
2029	94,06	93,99	91.23	88.74	87.97	88.15	87.71	88.06	88.61	89.34	98,37	98.11
2030	97.60	97.54	94.87	92,62	92.40	92.57	92.61	93.00	93.12	93,68	102.42	102.70
2031	99.56	99.50	96.78	94.48	94.26	94.43	94,47	94,87	94.99	95,56	104.47	104.76
2032	103.85	103.80	100.57	98.18	97.96	98.15	98.23	98.65	98.76	99.36	108.86	109,41
2033	106.56	106.51	103.17	100.72	100.50	100.69	100.78	101.21	101.32	101,93	111.67	112.26
2034	109.12	109,07	105.60	103.10	102.88	103.08	103.17	103.61	103.72	104.35	114.33	114.96
2035	111.55	111.51	107.91	105.35	105.12	105.33	105.43	105.89	105.99	106.63	116,87	117.54
2036	113.85	113.80	110.14	107.53	107.30	107.51	107.60	108.07	108.18	108.83	119.27	119.95
2037	116.50	116.45	112.72	110.06	109.82	110.04	110.14	110.61	110,73	111.39	122.03	122.73
2038	119.08	119.03	115.22	112.51	112.27	112.49	112.59	113.08	113.19	113.87	124.71	125.42
2039	121.47	121.42	117.54	114.77	114.53	114.75	114.85	115.35	115.47	116.15	127.21	127.93
2040	124.25	124.20	120.25	117.43	117.18	117.41	117.51	118.02	118.14	118.84	130.10	130.85
2041	126.72	126.67	122,64	119.76	119.51	119.74	119.85	120,36	120.49	121,20	132.68	133.44

		<u> </u>			T/	ABLE 1b						
					Avol	ded Cost	s					
			Sta	andard Fi	xed Price	Option	for Base	Load QF				
				0	ff-Peak F	orecast (\$/MWH)					
			Ì						į			
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	<u>Dec</u>
2016	25.61	20.71	13.96	11.41	6.31	10.11	15.71	20.96	20,96	21.21	23,46	26.71
2017	25.71	24.21	22.21	15.71	13.71	12.71	19.71	25.21	25.46	24.71	25.71	27.96
2018	26.17	28.12	25.56	19.46	14.68	12.54	19.71	27.04	26.93	25.35	28.20	30.62
2019	29.84	28.09	25.75	18.15	15.81	14.64	22,83	29.26	29.55	28.67	29.84	32.47
2020	31.75	29.88	27.38	19.28	16.79	15.54	24.27	31.12	31.43	30.50	31.75	34.55
2021	28,88	28.79	26.86	26.15	25.87	25,95	26.07	26.19	26.30	26,94	30.06	30.18
2022	29.73	29.56	28.79	27.85	27,53	27.63	27.75	27.88	28.00	28.54	32.09	32.42
2023	31.78	31.59	30.21	29.01	28.90	29.00	29,14	29,27	29.40	29,95	33.38	33.52
2024	33.48	33.16	31,98	30.60	30.41	30.52	30.66	30,81	30.95	31.51	35.80	35.96
2025	35.58	35.69	34.24	33.27	33.42	33,53	33.70	33,86	34.01	34.19	40.97	41.28
2026	42.77	42.89	40.36	38.87	38.81	38.95	39.15	39.34	39.50	39.95	46.62	46,31
2027	43.63	43.54	41.91	39,89	39.66	39.80	39.77	40.09	40.24	40.74	48.16	47.92
2028	45.26	45.25	43.90	41.40	41,23	41.40	41.25	41.58	41.89	42.59	50,60	49.48
2029	49.15	49.08	46.32	43.83	43.06	43.24	42.80	43.15	43.70	44.43	53.46	53,20
2030	51,82	51.76	49.09	46.84	46.62	46.79	46,83	47.22	47.34	47.90	56.64	56,92
2031	52.90	52.84	50.11	47.82	47.59	47.77	47.81	48.21	48.33	48.90	57.81	58.10
2032	56.59	56.54	53.31	50.92	50.70	50.89	50.97	51.39	51.50	52.10	61.60	62.15
2033	58.08	58.03	54.69	52.24	52.02	52.21	52.30	52.73	52,84	53.45	63.19	63,78
2034	59,54	59.50	56.03	53.52	53.30	53.50	53.59	54.04	54.15	54.77	64.76	65.39
2035	61.18	61.14	57.54	54.98	54.75	54.96	55.06	55.52	55.62	56,26	66.50	67.17
2036	62.67	62.62	58,96	56.35	56.12	56.33	56.43	56,89	57.00	57.65	68.09	68.78
2037	64.17	64.12	60.39	57.73	57.49	57.71	57.80	58,28	58.39	59.06	69.69	70.39
2038	65.73	65.69	61,88	59.17	58.93	59.15	59.25	59.73	59,85	60.52	71.37	72.08
2039	67.09	67.04	63.16	60.40	60.15	60.38	60.48	60.98	61.09	61.78	72.83	73,56
2040	68.83	68.78	64.83	62.01	61.76	61.99	62.09	62.60	62.72	63.42	74.68	75.42
2041	70.23	70.17	66,14	63.27	63.02	63.25	63.36	63.87	63.99	64.71	76.19	76.95

					T/	ABLE 2a	·	· · · ·				
						ded Cos	ts		•			
				Standard	I Fixed P	rice Opti	on for Wi	ind QF				
				0	n-Peak F	orecast (\$/MWH)					
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	24.37	18,62	11.77	10.87	8.62	13.12	20.12	23.12	21.12	19.87	22.87	27.62
2017	26,05	24.30	20.80	17.05	15.55	16.55	24.05	27,05	25.55	23.80	24.80	29,80
2018	27.72	27.12	24.12	18,14	17.29	17.29	25.94	29.38	26.64	24.62	27.87	31.72
2019	29,87	27.88	23.90	19.63	17.93	19.06	27.60	31.01	29,30	27,31	28,45	34.14
2020	31.59	29.49	25.30	20.80	19.00	20.20	29.19	32.79	30.99	28.89	30.09	36.09
2021	30.68	30.59	28.66	27.94	27.66	27.75	27.87	27.99	28,10	28.74	31.86	31.98
2022	31.56	31.39	30.62	29.68	29.36	29.46	29.59	29.72	29.84	30.38	33.93	34.25
2023	33,67	33.48	32.11	30.91	30.79	30.90	31.03	31.17	31.30	31.84	35.28	35,42
2024	35.38	35.06	33.88	32.49	32.30	32.42	32.56	32.70	32.84	33.40	37.70	37.85
2025	37.53	37.64	36.18	35.22	35,36	35.48	35.64	35,81	35,96	36,14	42.91	43.23
2026	44.75	44.87	42.35	40.86	40.79	40.94	41.13	41.32	41.48	41.94	48.60	48.29
2027	45.65	45.56	43.93	41.91	41.68	41,82	41.79	42.12	42.26	42.76	50.18	49.94
2028	47.32	47.31	45.96	43.46	43.30	43,46	43.31	43.64	43.95	44.65	52.66	51.55
2029	51.25	51.18	48.43	45.94	45.16	45.34	44.90	45.25	45.80	46.53	55.57	55,30
2030	53,96	53,90	51.23	48.98	48.76	48.93	48.97	49.36	49.48	50.04	58.78	59.06
2031	55.08	55.02	52.29	50.00	49.77	49.95	49,99	50.38	50.51	51.08	59.99	60.28
2032	58.77	58.72	55.49	53.10	52,88	53.07	53.15	53.57	53,68	54.28	63.78	64.33
2033	60.35	60.30	56.96	54,51	54.29	54.49	54.57	55.00	55.11	55.72	65.46	66,05
2034	61,88	61.83	58.36	55.86	55,63	55.84	55.93	56.37	56,48	57.10	67.09	67.72
2035	63.54	63,49	59.90	57.34	57.11	57,32	57.42	57.87	57.98	58.62	68.86	69.53
2036	65.04	65.00	61.33	58.72	58.49	58.70	58.80	59.27	59,38	60.03	70.46	71.15
2037	66.61	66.57	62.83	60.17	59.93	60.15	60.25	60.73	60.84	61.50	72.14	72.84
2038	68.23	68.18	64.37	61.66	61.42	61.64	61.74	62.23	62.34	63.02	73,86	74.57
2039	69.64	69.59	65.71	62.94	62.70	62.92	63.03	63.52	63,64	64.33	75.38	76.11
2040	71.42	71.37	67,41	64.60	64.35	64.58	64.68	65.18	65.30	66.00	77.27	78.01
2041	72.87	72.82	68.79	65.92	65,66	65.90	66.00	66.52	66.64	67.35	78.84	79.59

					T/	BLE 2b						
						ded Cost	:5					
				Standard	Fixed P	rice Optic	n for Wi	nd QF				
				0	ff-Peak F	orecast (\$/MWH)					
							Ì]			
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct_	Nov	Dec
2016	21.77	16.87	10.12	7.57	2.47	6,27	11.87	17.12	17.12	17.37	19.62	22.87
2017	21.80	20.30	18.30	11.80	9.80	8,80	15.80	21,30	21.55	20.80	21.80	24.05
2018	22.18	24.13	21.57	15.47	10.69	8,55	15.72	23.05	22.94	21.36	24.21	26.63
2019	25.77	24.02	21.68	14.08	11.74	10.57	18.76	25.19	25.48	24.60	25.77	28.40
2020	27.60	25.73	23.23	15.13	12.64	11.39	20.12	26.97	27.28	26.35	27.60	30.40
2021	24.65	24.56	22.63	21.92	21.64	21.72	21.84	21.96	22.07	22.71	25.83	25.95
2022	25.42	25.25	24.48	23.54	23.22	23.32	23.44	23.57	23.69	24.23	27.78	28.11
2023	27.39	27.20	25.82	24.62	24.51	24,61	24.75	24.88	25.01	25.56	28.99	29,13
2024	29.01	28,69	27.51	26.13	25.94	26.05	26.19	26.34	26.48	27.04	31.33	31.49
2025	31.02	31.13	29.68	28.71	28.86	28.97	29.14	29.30	29.45	29.63	36.41	36.72
2026	38.12	38,24	35.71	34.22	34.16	34.30	34.50	34,69	34.85	35,30	41.97	41.66
2027	38.89	38.80	37.17	35.15	34.92	35.06	35.03	35.35	35,50	36.00	43.42	43.18
2028	40.43	40.42	39.07	36.57	36.40	36,57	36.42	36,75	37.06	37.76	45.77	44,65
2029	44.23	44.16	41.40	38.91	38.14	38.32	37.88	38,23	38.78	39,51	48.54	48.28
2030	46,80	46.74	44.07	41.82	41.60	41.77	41.81	42.20	42.32	42.88	51.62	51.90
2031	47.78	47.72	44.99	42.70	42.47	42.65	42.69	43.09	43.21	43.78	52.69	52.98
2032	51.38	51.33	48.10	45.71	45.49	45.68	45.76	46.18	46.29	46.89	56.39	56,94
2033	52.77	52.72	49.38	46.93	46.71	46.90	46.99	47.42	47.53	48.14	57.88	58.47
2034	54.12	54.08	50.61	48,10	47.88	48.08	48.17	48.62	48.73	49,35	59,34	59.97
2035	55.66	55.62	52.02	49.46	49.23	49.44	49.54	50.00	50.10	50.74	60.98	61.65
2036	57.04	56.99	53.33	50.72	50.49	50.70	50.80	51.26	51.37	52.02	62.46	63,15
2037	58.43	58.38	54.65	51.99	51.75	51.97	52.06	52.54	52.65	53.32	63,95	64.65
2038	59.88	59.84	56.03	53.32	53.08	53.30	53.40	53.88	54.00	54.67	65.52	66.23
2039	61.13	61.08	57.20	54.44	54,19	54.42	54.52	55.02	55.13	55.82	66.87	67.60
2040	62.75	62.70	58.75	55.93	55.68	55.91	56.01	56.52	56.64	57.34	68.60	69.34
2041	64.04	63.98	59.95	57.08	56.83	57.06	57.17	57.68	57,80	58.52	70.00	70.76

,					T	ABLE 3a						
					Avol	ded Cost	ts					
				Standard	i Fixed P	rice Opti	on for So	lar QF				
				0	n-Peak F	orecast (\$/MWH)					
								1				
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	28.21	22.46	15.61	14.71	12.46	16.96	23.96	26.96	24,96	23.71	26.71	31.46
2017	29.96	28.21	24.71	20.96	19.46	20.46	27.96	30.96	29.46	27.71	28,71	33.71
2018	31.71	31.11	28.11	22.13	21.28	21.28	29.93	33.37	30.63	28.61	31.86	35.71
2019	33.94	31.95	27.97	23,70	22.00	23.13	31.67	35.08	33.37	31.38	32.52	38.21
2020	35.74	33.64	29.45	24.95	23.15	24.35	33.34	36.94	35.14	33.04	34.24	40,24
2021	33.98	33.89	31.96	31.24	30.96	31.05	31.16	31.28	31.39	32.03	35.15	35.27
2022	34.92	34.75	33.98	33.04	32.72	32.82	32,94	33.08	33.20	33.74	37.28	37.61
2023	37.09	36,90	35.52	34.32	34.21	34.31	34.44	34.58	34.71	35,26	38.69	38.83
2024	38.86	38.54	37.36	35.98	35.79	35.90	36.04	36,19	36.32	36.88	41.18	41.33
2025	41.08	41,19	39.73	38.77	38.92	39.03	39.19	39.36	39,51	39.69	46.46	46.78
2026	48.37	48.49	45.97	44.48	44.42	44,56	44.75	44.94	45.10	45.56	52,22	51.91
2027	49,34	49.25	47.62	45.61	45.38	45.51	45.48	45.81	45.95	46.45	53.87	53.63
2028	51.08	51.07	49.72	47.22	47.06	47.22	47.07	47.40	47.72	48.41	56.42	55.31
2029	55.08	55.01	52.26	49.77	48.99	49.17	48.73	49.08	49.63	50.36	59.40	59.13
2030	57.87	57.81	55.14	52,89	52.67	52.84	52.88	53.27	53.39	53.95	62.69	62.97
2031	59.07	59.00	56.28	53.98	53.76	53.93	53.98	54.37	54.49	55.06	63.98	64,26
2032	62.83	62.78	59.56	57.16	56,94	57.13	57.21	57.64	57.75	58.34	67.85	68.39
2033	64.49	64.44	61.09	58.64	58.42	58.62	58.70	59.14	59.25	59.86	69.60	70.18
2034	66.10	66.05	62.58	60.08	59.85	60.05	60,14	60.59	60.70	61.32	71.31	71.94
2035	67.84	67.79	64.20	61.64	61.41	61.62	61.71	62.17	62.28	62.92	73.16	73.83
2036	69,43	69.38	65,72	63,11	62.88	63.09	63.19	63.66	63,77	64.42	74.85	75,54
2037	71.08	71.04	67,30	64.64	64.40	64.62	64.72	65.20	65.31	65.97	76.61	77.31
2038	72.78	72.73	68.93	66.22	65.98	66.20	66.30	66.78	66.90	67.57	78.42	79.13
2039	74.28	74.23	70.35	67.58	67.34	67.56	67.67	68.16	68.28	68.97	80.02	80.75
2040	76.15	76.10	72.15	69.33	69.08	69.31	69.42	69.92	70.04	70.74	82.01	82.75
2041	77.69	77.64	73.61	70.74	70.48	70.72	70.82	71.34	71.46	72.17	83.66	84.41

					T/	ABLE 3b						
					Avoi	ded Cos	ts					
				Standard	fixed P	rice Opti	on for So	lar QF				
-				0	ff-Peak F	orecast (\$/MWH)					
						~						_
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	25.61	20.71	13.96	11.41	6,31	10.11	15,71	20.96	20.96	21.21	23.46	26.71
2017	25.71	24.21	22.21	15.71	13.71	12.71	19.71	25.21	25.46	24.71	25.71	27.96
2018	26.17	28.12	25.56	19.46	14.68	12.54	19.71	27.04	26.93	25.35	28.20	30.62
2019	29.84	28.09	25.75	18.15	15.81	14.64	22,83	29.26	29.55	28.67	29.84	32.47
2020	31.75	29.88	27.38	19.28	16.79	15.54	24.27	31.12	31.43	30,50	31.75	34.55
2021	28.88	28.79	26.86	26.15	25.87	25.95	26,07	26.19	26.30	26.94	30.06	30.18
2022	29.73	29.56	28.79	27.85	27.53	27.63	27.75	27.88	28.00	28.54	32.09	32.42
2023	31.78	31.59	30.21	29.01	28.90	29.00	29,14	29.27	29.40	29.95	33.38	33.52
2024	33,48	33.16	31.98	30.60	30,41	30.52	30,66	30.81	30.95	31.51	35.80	35.96
2025	35,58	35,69	34.24	33.27	33.42	33.53	33.70	33.86	34.01	34.19	40.97	41.28
2026	42.77	42.89	40.36	38.87	38.81	38.95	39.15	39.34	39.50	39,95	46.62	46.31
2027	43.63	43.54	41.91	39.89	39.66	39,80	39.77	40.09	40.24	40.74	48.16	47.92
2028	45.26	45,25	43.90	41.40	41.23	41.40	41.25	41.58	41.89	42.59	50.60	49.48
2029	49.15	49.08	46.32	43.83	43.06	43.24	42.80	43.15	43.70	44.43	53.46	53.20
2030	51.82	51.76	49.09	46.84	46.62	46.79	46.83	47.22	47.34	47.90	56,64	56.92
2031	52,90	52.84	50.11	47.82	47.59	47.77	47.81	48.21	48.33	48.90	57.81	58.10
2032	56.59	56.54	53.31	50.92	50.70	50.89	50.97	51.39	51.50	52,10	61.60	62,15
2033	58.08	58.03	54.69	52.24	52,02	52.21	52.30	52.73	52,84	53,45	63.19	63.78
2034	59.54	59.50	56.03	53,52	53.30	53,50	53.59	54.04	54.15	54.77	64.76	65.39
2035	61.18	61.14	57.54	54.98	54.75	54.96	55.06	55.52	55.62	56.26	66.50	67.17
2036	62.67	62.62	58.96	56.35	56.12	56.33	56.43	56.89	57.00	57.65	68.09	68.78
2037	64.17	64.12	60.39	57.73	57.49	57.71	57.80	58.28	58.39	59.06	69.69	70.39
2038	65.73	65.69	61,88	59.17	58.93	59.15	59.25	59.73	59.85	60.52	71.37	72.08
2039	67.09	67.04	63.16	60.40	60.15	60.38	60.48	60.98	61.09	61.78	72.83	73.56
2040	68.83	68.78	64.83	62.01	61.76	61.99	62.09	62.60	62.72	63.42	74.68	75.42
2041	70.23	70.17	66.14	63.27	63.02	63.25	63.36	63.87	63.99	64.71	76.19	76.95

PRICING OPTIONS FOR STANDARD PPA (Continued)

2) Renewable Fixed Price Option

The Renewable Fixed Price Option is based on Renewable Avoided Costs. It is available only to Renewable QFs that generate electricity from a renewable energy source that may be used by the Company to comply with the Oregon Renewable Portfolio Standard as set forth in ORS 469A.005 to 469A.210.

This option is available for a maximum term of 15 years. Prices will be as established at the time the Standard PPA is executed and will be equal to the Renewable Avoided Costs in Tables 4a and 4b, 5a and 5b, or 6a and 6b, depending on the type of QF, effective at execution. QFs using any resource type other than wind and solar are assumed to be Base Load QFs.

Sellers will retain all Environmental Attributes generated by the facility during the Renewable Resource Sufficiency Period. A Renewable QF choosing the Renewable Fixed Price Option must cede all RPS Attributes generated by the facility to the Company from the start of the Renewable Resource Deficiency Period through the remainder of the PPA term.

Prices paid to the Seller under the Renewable Fixed Price Option include adjustments for the capacity contribution of the QF resource type relative to that of the avoided proxy resource. Both Wind QF resources (Tables 5a and 5b) and the avoided proxy resource, the basis used to determine Renewable Avoided Costs for the Renewable Fixed Price Option, are assumed to have a capacity contribution to peak of 5%. The capacity contribution for Solar QF resources (Tables 6a and 6b) is assumed to be 5%. The capacity contribution for Base Load QF resources (Tables 4a and 4b) is assumed to be 100%.

The Renewable Avoided Costs during the Renewable Resource Deficiency Period reflect an increase for avoided wind integration costs, shown in Table 7.

Prices paid to the Seller under the Renewable Fixed Price Option for Wind QFs (Tables 5a and 5b) include a reduction for the wind integration costs in Table 7, which cancels out wind integration costs included in the Renewable Avoided Costs during the Renewable Resource Deficiency Period. However, if the Wind QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the wind integration charges in Table 7, in addition to the prices listed in Tables 5a and 5b.

Sellers with PPAs exceeding 15 years will receive pricing equal to the Mid-C Index Price for all years up to five in excess of the initial 15.

					T	ABLE 4a						
				F	Renewabl	e Avolde	d Costs					
			Rei					<u> Load Q</u>	F			
				0	n-Peak F	orecast	\$/MWH)			i	1	ı
								•		.	3.	
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	28.36	22.61	15.76	14.86	12.61	17.11	24.11	27.11	25.11	23.86	26.86	31.61
2017	30.11	28.36	24.86	21.11	19.61	20.61	28.11	31.11	29.61	27.86	28.86	33,86
2018	31.86	31.26	28.26	22.28	21.43	21.43	30.08	33.52	30.78	28.76	32.01	35.86
2019	34.10	32.11	28.13	23.86	22.16	23.29	31.83	35.24	33.53	31.54	32.68	38.37
2020	115,34	115.32	114.56	115.02	118.22	117.33	117.01	116.89	115.60	114.63	115.47	114.45
2021	117.94	118.18	116.67	117.75	120.59	119.83	119.26	119.77	118.26	117.25	118.55	117.22
2022	120.48	120.36	118.46	120.19	123,17	122.14	121.69	121.65	120.55	119.55	120.98	119.53
2023	123.26	122,83	120.85	122.92	125.37	124.64	124.29	123.92	123,08	121.92	123,63	122.53
2024	124.86	125.01	123.06	125.07	127.80	126,78	126.67	126.41	126.22	123.83	124.83	124.96
2025	127.73	128.05	125.86	128.21	131.66	130.48	129,53	129.66	128.84	126.59	127.76	127.41
2026	130.91	130.58	129.12	131.30	135.76	132.28	132.28	132.69	132.40	129.34	131.17	130.23
2027	133.47	133.03	131.38	133.50	139.48	134.88	134.51	135,95	134.79	131.96	133.26	132.78
2028	135.95	134.91	132.89	136,24	141.79	136.93	137.64	137.65	136.77	134.76	135.84	135.06
2029	138.81	138.57	135.91	139.29	149.30	140.74	140.82	140.82	140.86	137.50	138.32	138.21
2030	141.68	141.39	139.11	142.00	153.18	145.20	143.05	142.93	144.31	140,18	140.75	140.79
2031	144.29	143.79	142.17	145.52	156.10	149.27	145.71	146.65	146.86	143.04	144.15	143.71
2032	146.51	146.00	144.35	147.76	158.51	151.58	147.95	148,91	149.13	145.24	146.37	145.92
2033	149.91	149.40	147.71	151.19	162.18	155.09	151.39	152.37	152.59	148.62	149.77	149.31
2034	152,96	152.43	150.71	154.26	165.46	158.24	154.46	155.46	155,68	151.64	152.81	152.35
2035	155,76	155,22	153.46	157.08	168,50	161.14	157.29	158.31	158.54	154.41	155,60	155.13
2036	158.31	157.76	155.97	159.65	171.26	163.78	159.86	160.90	161.13	156.94	158.15	157.67
2037	161.83	161.27	159,44	163.20	175.07	167.42	163,42	164.48	164.71	160.43	161.67	161.18
2038	164.95	164.38	162.52	166.35	178.45	170.65	166.57	167.65	167,89	163.52	164.79	164.29
2039	168.13	167.55	165.66	169.56	181.89	173.94	169.79	170,89	171.13	166.68	167.97	167.46
2040	171.05	170.46	168.54	172.51	185.04	176.96	172.74	173,85	174.10	169.58	170.89	170.37
2041	174.69	174.08	172.11	176.17	188.98	180.72	176.40	177.55	177.80	173.18	174.52	173.99

					T/	ABLE 4b						
				R	Renewabl	e Avoided	l Costs					
			Rer	ewable F	ixed Pric	e Option	for Base	Load Q	3			
				<u>O</u>	ff-Peak F	orecast (\$/MWH)					
			<u> </u>									
Year	Jan	Feb	Mar	Apr	May	Jun	<u>Jul</u>	Aug	Sep	Oct	Nov	Dec
2016	25,76	20.86	14,11	11.56	6.46	10.26	15.86	21.11	21.11	21.36	23.61	26.86
2017	25.86	24.36	22.36	15.86	13,86	12.86	19.86	25.36	25.61	24.86	25.86	28.11
2018	26.32	28.27	25.71	19.61	14.83	12.69	19.86	27.19	27.08	25,50	28.35	30.77
2019	30.00	28.25	25.91	18.31	15.97	14.80	22.99	29.42	29.71	28.83	30.00	32.63
2020	62.76	63.02	64.56	63.31	59.92	60,16	60,45	61.61	62.52	63.74	63,55	63.99
2021	64.93	64.15	65.85	64.48	61.58	61,62	62.27	62.62	63.78	65.82	63.38	65.09
2022	65.85	65.52	67.77	65.49	62.45	62.82	64.33	63,35	65.00	67.04	64.42	66.29
2023	66.70	66.75	69.10	67.28	62.84	64.01	65,40	64.85	66.14	68.41	65.38	67.63
2024	67.25	67.31	70,47	67.09	63.18	65.92	64.75	65.12	66.62	68.68	67,42	68,05
2025	68.62	68,60	71.94	68.08	63.17	66.28	66.12	67.12	67.23	70.19	69.68	69.06
2026	68.95	69,85	72.28	68.56	63.85	67.22	67.05	67.75	67.05	71.12	69.85	69.89
2027	71.31	71.29	73.13	70.34	63.69	68.45	68.79	68,16	68.57	73.22	70.67	71.18
2028	72,28	72.90	75,41	72.10	63.09	69,98	70.15	68.82	70,20	73.79	71.48	73.41
2029	72.78	73.60	76.79	73.50	58,25	70.29	71.37	70.00	71.53	74.58	73.61	74.68
2030	73.91	74.82	78.36	73.64	58.00	70.89	72.02	72.19	72.00	75.99	75.36	76.23
2031	75.51	76.70	79.40	74.00	59.17	70.67	73,55	73.71	72.16	77.24	77.07	76.31
2032	76.76	77.97	80.71	75.23	60.15	71.83	74.76	74.93	73,35	78.52	78.34	77.57
2033	78.46	79.69	82.50	76.89	61,48	73.42	76.42	76.58	74.97	80.25	80.07	79.29
2034	79.97	81.23	84.09	78.37	62.66	74.84	77.89	78.06	76.42	81.80	81.62	80.82
2035	81.52	82.80	85.71	79.88	63.87	76.28	79.39	79.57	77.89	83,38	83.19	82.38
2036	82.86	84.17	87.13	81.20	64.93	77.54	80.70	80.88	79.18	84.76	84.57	83.74
2037	84.69	86.03	89.05	83.00	66.36	79.25	82.49	82.67	80.93	86.63	86.44	85,59
2038	86.33	87.69	90.77	84.60	67.64	80.78	84.08	84.26	82.49	88.30	88.11	87.24
2039	87.99	89.38	92.52	86.23	68.95	82.34	85.70	85.89	84.08	90.01	89.81	88.92
2040	89.45	90.85	94.05	87.66	70.09	83.70	87.12	87.31	85.47	91.49	91.29	90.39
2041	91.42	92.86	96.13	89.59	71.63	85,55	89.04	89.24	87,36	93.51	93.31	92.39

					T	ABLE 5a						
					Renewabl	Consider the second						
					le Fixed F			ind QF	*****			
				0	n-Peak F	<u>orecast (</u>	\$/MWH)					
		-				_			A	0-1	Mare	Das
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov 23.02	Dec 27,77
2016	24.52	18.77	11.92	11.02	8.77	13.27	20.27	23.27	21.27	20.02		
2017	26.20	24,45	20.95	17.20	15.70	16.70	24.20	27.20	25.70	23.95	24.95	29.95
2018	27,87	27.27	24.27	18.29	17.44	17.44	26.09	29.53	26.79	24.77	28.02	31.87
2019	30.03	28.04	24.06	19.79	18.09	19.22	27.76	31.17	29.46	27.47	28.61	34.30
2020	75.38	75.37	74.61	75.06	78.26	77.37	77.05	76.93	75.64	74.67	75.51	74.49
2021	77.10	77.33	75.83	76.90	79.75	78.99	78.41	78.92	77.41	76.40	77.70	76.38
2022	78.85	78.72	76.82	78.56	81.53	80.51	80.05	80,02	78.92	77.92	79.34	77.90
2023	80.71	80.27	78.29	80.37	82.82	82.08	81.73	81.37	80.53	79.36	81.08	79.97
2024	81.74	81.89	79.93	81.95	84.68	83.66	83.55	83.28	83.10	80.71	81.71	81.84
2025	83,64	83.97	81.78	84.13	87.57	86.40	85.44	85.57	84.75	82.51	83.68	83.32
2026	85.97	85.64	84.18	86.37	90.82	87.34	87,34	87.75	87.46	84.40	86.23	85.29
2027	87.67	87.23	85.57	87,69	93.67	89.07	88.71	90.15	88.99	86,16	87.45	86.98
2028	89.26	88.22	86.20	89.55	95.10	90.24	90.95	90.96	90.08	88.07	89,15	88.37
2029	91.22	90.98	88.32	91.70	101.72	93.16	93.23	93.23	93.28	89.92	90.73	90.62
2030	93.17	92.88	90.60	93.49	104.67	96.69	94,54	94.42	95.80	91.67	92.24	92.28
2031	94.84	94.34	92.72	96.07	106.65	99.82	96.26	97.20	97,42	93.59	94.70	94.26
2032	96,40	95.90	94.24	97.65	108.40	101.47	97.85	98.80	99.02	95.13	96.26	95.82
2033	98.55	98.03	96.34	99.82	110.81	103.72	100.02	101.00	101.22	97.25	98.40	97.95
2034	100.44	99.91	98,19	101.74	112.94	105.72	101.94	102.94	103.17	99.12	100.29	99.83
2035	102.38	101.85	100.09	103.71	115,13	107.76	103.92	104.93	105.16	101.04	102.23	101.76
2036	104.06	103.51	101.72	105.40	117.01	109.53	105.61	106.65	106.88	102.69	103.90	103.42
2037	106.37	105.81	103.99	107.74	119.61	111.96	107.96	109.02	109.26	104.97	106.21	105.72
2038	108.42	107.86	105.99	109.82	121.92	114.12	110.05	111.12	111,37	107.00	108.26	107.76
2039	110.52	109.94	108.04	111.95	124.27	116.33	112.17	113.27	113.52	109.07	110.36	109.85
2040	112.32	111.73	109,81	113.77	126,31	118.23	114.00	115.12	115.37	110.85	112.16	111.64
2041	114.83	114.23	112.26	116.31	129.12	120,86	116.55	117.69	117.95	113.32	114.66	114.13

					TA	ABLE 5b						
				R	enewabl	e Avoided	Costs					
			F	Renewabl	e Fixed F	rice Opti	on for W	ind QF				
				0	ff-Peak F	orecast (\$/MWH)					
1				-						0.1		
Year	<u>Jan</u>	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	21.92	17.02	10.27	7.72	2.62	6.42	12.02	17.27	17.27	17.52	19.77	23.02
2017	21.95	20.45	18.45	11.95	9.95	8.95	15.95	21.45	21,70	20.95	21.95	24.20
2018	22,33	24.28	21.72	15.62	10.84	8.70	15.87	23.20	23.09	21.51	24.36	26.78
2019	25.93	24.18	21.84	14.24	11.90	10.73	18.92	25,35	25.64	24.76	25.93	28.56
2020	58.61	58.87	60.41	59.16	55.77	56.01	56.30	57.46	58.37	59.59	59.40	59.84
2021	60,70	59.92	61.62	60.25	57.35	57,39	58.04	58.39	59.55	61.59	59.15	60.86
2022	61.54	61.21	63.46	61.18	58.14	58,51	60.02	59.04	60.69	62.73	60.11	61.98
2023	62.31	62.36	64.71	62.89	58,45	59.62	61.01	60.46	61.75	64.02	60.99	63.24
2024	62.78	62.84	66.00	62.62	58.71	61.45	60.28	60.65	62.15	64.21	62.95	63.58
2025	64,06	64.04	67.38	63.52	58,61	61.72	61.56	62.56	62.67	65,63	65.12	64.50
2026	64.30	65.20	67.63	63.91	59,20	62.57	62.40	63.10	62.40	66,47	65.20	65.24
2027	66.57	66.55	68.39	65.60	58,95	63.71	64.05	63,42	63.83	68.48	65.93	66.44
2028	67.45	68.07	70,58	67.27	58.26	65.15	65.32	63.99	65.37	68.96	66,65	68.58
2029	67.86	68.68	71.87	68.58	53.33	65.37	66.45	65.08	66.61	69.66	68.69	69.76
2030	68.89	69.80	73.34	68,62	52.98	65.87	67.00	67.17	66.98	70,97	70.34	71.21
2031	70.39	71.58	74.28	68.88	54.05	65.55	68.43	68.59	67.04	72.12	71.95	71.19
2032	71.55	72.76	75.50	70.02	54.94	66.62	69.55	69.72	68.14	73.31	73.13	72.36
2033	73.15	74.38	77.19	71,58	56.17	68.11	71.11	71.27	69.66	74.94	74.76	73.98
2034	74.55	75.81	78.67	72.95	57.24	69.42	72.47	72.64	71.00	76.38	76.20	75.40
2035	76.00	77.28	80.19	74.36	58.35	70.76	73.87	74.05	72.37	77.86	77.67	76.86
2036	77.23	78.54	81.50	75.57	59.30	71.91	75.07	75.25	73.55	79.13	78.94	78.11
2037	78.95	80.29	83.31	77.26	60.62	73.51	76.75	76.93	75.19	80.89	80.70	79.85
2038	80.48	81.84	84.92	78.75	61.79	74.93	78.23	78.41	76.64	82.45	82.26	81.39
2039	82.03	83.42	86.56	80.27	62.99	76.38	79.74	79.93	78.12	84.05	83.85	82.96
2040	83.37	84.77	87.97	81.58	64.01	77.62	81.04	81.23	79.39	85.41	85.21	84.31
2041	85.23	86.67	89.94	83.40	65.44	79.36	82.85	83.05	81.17	87.32	87.12	86.20

					Τ.	ABLE 6a						
				F	Renewab!	e Avoide	d Costs					
				Renewab	le Fixed I	rice Opt	lon for S	olar QF			·····	
				0	n-Peak F	orecast	(\$/MWH)				1	
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	28.36	22.61	15.76	14.86	12.61	17.11	24.11	27.11	25.11	23.86	28.86	31.61
2017	30,11	28.36	24.86	21.11	19.61	20,61	28,11	31.11	29.61	27.86	28.86	33,86
2018	31.86	31.26	28.26	22.28	21.43	21,43	30.08	33.52	30.78	28.76	32.01	35.86
2019	34.10	32.11	28.13	23.86	22,16	23.29	31.83	35.24	33,53	31.54	32.68	38,37
2020	78.62	78.60	77.84	78.30	81.50	80.60	80.29	80.17	78.88	77.91	78.74	77.73
2021	80.39	80.63	79.12	80.20	83,04	82.28	81.71	82.22	80.71	79.70	81.00	79.67
2022	82.21	82.08	80.18	81.92	84.89	83.87	83.41	83.38	82.27	81.27	82.70	81.25
2023	84.12	83.69	81.71	83.78	86.23	85.50	85,15	84.78	83.94	82,78	84.50	83.39
2024	85,22	85.37	83.41	85.43	88.16	87.14	87.03	86.76	86.58	84,19	85.19	85.32
2025	87.19	87.52	85.33	87.68	91.12	89.95	88.99	89.12	88.30	86.06	87.23	86.87
2026	89,59	89.26	87.80	89.99	94.44	90.96	90.96	91.37	91.08	88.02	89.85	88.91
2027	91.36	90.92	89.26	91.39	97.36	92.76	92.40	93,84	92.68	89,85	91.14	90.67
2028	93.02	91.98	89.96	93,31	98.86	94.00	94.71	94.72	93.84	91.84	92,91	92,13
2029	95.05	94.81	92.15	95.53	105.55	96.99	97.06	97.06	97.11	93.75	94.56	94.45
2030	97.08	96.79	94.51	97.40	108.58	100.60	98.45	98.33	99.71	95.58	96.15	96.19
2031	98.83	98.33	96.70	100.05	110.63	103.81	100.25	101.19	101.40	97.58	98.69	98.25
2032	100.47	99,96	98.30	101.71	112.47	105.53	101.91	102.87	103.08	99.20	100.32	99.88
2033	102.68	102.16	100.47	103.95	114.95	107.86	104,16	105.14	105.36	101.38	102.53	102,08
2034	104.66	104.13	102.41	105.96	117.16	109.94	106.16	107.16	107.38	103.34	104.51	104.05
2035	106.68	106.15	104.39	108.01	119.43	112.06	108.21	109.23	109.46	105.34	106.53	106.06
2036	108.44	107.90	106.11	109.79	121.40	113.91	110.00	111.04	111.27	107.08	108.29	107.81
2037	110.84	110.28	108.46	112.21	124.08	116.43	112.43	113.49	113.73	109.44	110.68	110.19
2038	112.98	112.41	110.55	114.38	126.47	118.68	114.60	115.68	115.92	111.55	112.82	112.32
2039	115.16	114.58	112.68	116.59	128.92	120.97	116.81	117.91	118.16	113.71	115.00	114.49
2040	117.06	116.47	114.54	118.51	131.04	122.96	118.74	119.86	120.11	115.58	116.89	116,37
2041	119.65	119.05	117.07	121.13	133.94	125.68	121.37	122.51	122.76	118.14	119.48	118.95

					T/	ABLE 6b						
	Renewable Avoided Costs											
Renewable Fixed Price Option for Solar QF												
Off-Peak Forecast (\$/MWH)												
				İ								
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	25.76	20,86	14.11	11.56	6,46	10,26	15.86	21.11	21.11	21.36	23.61	26.86
2017	25,86	24.36	22.36	15.86	13.86	12.86	19.86	25.36	25.61	24.86	25.86	28.11
2018	26.32	28.27	25.71	19.61	14.83	12,69	19.86	27,19	27.08	25.50	28.35	30.77
2019	30.00	28.25	25.91	18.31	15.97	14.80	22.99	29.42	29.71	28.83	30.00	32.63
2020	62,76	63.02	64.56	63.31	59,92	60.16	60.45	61.61	62.52	63.74	63.55	63.99
2021	64.93	64.15	65.85	64.48	61.58	61.62	62.27	62.62	63.78	65.82	63.38	65.09
2022	65.85	65.52	67.77	65.49	62.45	62.82	64,33	63.35	65.00	67.04	64.42	66.29
2023	66.70	66.75	69.10	67.28	62.84	64.01	65.40	64,85	66.14	68.41	65.38	67.63
2024	67.25	67.31	70.47	67.09	63.18	65.92	64.75	65.12	66.62	68.68	67.42	68.05
2025	68.62	68.60	71.94	68.08	63.17	66.28	66.12	67.12	67.23	70.19	69,68	69.06
2026	68,95	69.85	72.28	68.56	63.85	67.22	67.05	67.75	67.05	71.12	69.85	69.89
2027	71.31	71.29	73.13	70.34	63.69	68.45	68.79	68.16	68.57	73.22	70.67	71.18
2028	72.28	72,90	75.41	72.10	63.09	69.98	70.15	68,82	70.20	73.79	71.48	73.41
2029	72,78	73.60	76.79	73.50	58.25	70.29	71.37	70.00	71.53	74.58	73.61	74.68
2030	73.91	74.82	78.36	73.64	58.00	70.89	72.02	72.19	72.00	75.99	75.36	76.23
2031	75.51	76.70	79.40	74.00	59.17	70,67	73.55	73.71	72.16	77.24	77.07	76.31
2032	76.76	77.97	80.71	75.23	60.15	71.83	74.76	74.93	73.35	78.52	78,34	77.57
2033	78,46	79.69	82.50	76.89	61.48	73.42	76.42	76.58	74.97	80.25	80.07	79.29
2034	79.97	81.23	84.09	78.37	62.66	74.84	77.89	78.06	76.42	81.80	81.62	80.82
2035	81.52	82.80	85.71	79.88	63.87	76.28	79.39	79.57	77.89	83,38	83.19	82.38
2036	82.86	84.17	87.13	81.20	64.93	77.54	80.70	80.88	79.18	84.76	84.57	83.74
2037	84.69	86.03	89.05	83.00	66.36	79,25	82.49	82.67	80.93	86.63	86.44	85,59
2038	86.33	87.69	90.77	84.60	67.64	80,78	84.08	84.26	82.49	88.30	88.11	87.24
2039	87.99	89.38	92.52	86.23	68.95	82,34	85.70	85.89	84.08	90.01	89.81	88.92
2040	89.45	90.85	94.05	87.66	70.09	83.70	87.12	87.31	85,47	91.49	91,29	90.39
2041	91.42	92.86	96.13	89.59	71.63	85.55	89.04	89.24	87.36	93.51	93.31	92.39

WIND INTEGRATION

TABLE 7						
Wind Integration						
Year	Cost					
2015	3.77					
2016	3.84					
2017	3.91					
2018	3.99					
2019	4.07					
2020	4.15					
2021	4.23					
2022	4.31					
2023	4.39					
2024	4.47					
2025	4.56					
2026	4.65					
2027	4.74					
2028	4.83					
2029	4.92					
2030	5.02					
2031	5.12					
2032	5,21					
2033	5,31					
2034	5,42					
2035	5.52					
2036	5,63					
2037	5.74					
2038	5.85					
2039	5.96					
2040	6.08					

MONTHLY SERVICE CHARGE

Each separately metered QF not associated with a retail Customer account will be charged \$10.00 per month.

INSURANCE REQUIREMENTS

The following insurance requirements are applicable to Sellers with a Standard PPA:

- 1) QFs with nameplate capacity ratings greater than 200 kW are required to secure and maintain a prudent amount of general liability insurance. The Seller must certify to the Company that it is maintaining general liability insurance coverage for each QF at prudent amounts. A prudent amount will be deemed to mean liability insurance coverage for both bodily injury and property damage liability in the amount of not less than \$1,000,000 each occurrence combined single limit, which limits may be required to be increased or decreased by the Company as the Company determines in its reasonable judgment, that economic conditions or claims experience may warrant.
- Such insurance will include an endorsement naming the Company as an additional insured insofar as liability arising out of operations under this schedule and a provision that such liability policies will not be canceled or their limits reduced without 30 days' written notice to the Company. The Seller will furnish the Company with certificates of insurance together with the endorsements required herein. The Company will have the right to inspect the original policies of such insurance.
- 3) QFs with a design capacity of 200 kW or less are encouraged to pursue liability insurance on their own. The Oregon Public Utility Commission in Order No. 05-584 determined that it is inappropriate to require QFs that have a design capacity of 200 kW or less to obtain general liability insurance.

TRANSMISSION AGREEMENTS

If the QF is located outside the Company's service territory, the Seller is responsible for the transmission of power at its cost to the Company's service territory.

INTERCONNECTION REQUIREMENTS

Except as otherwise provided in a generation Interconnection Agreement between the Company and Seller, if the QF is located within the Company's service territory, switching equipment capable of isolating the QF from the Company's system will be accessible to the Company at all times. At the Company's option, the Company may operate the switching equipment described above if, in the sole opinion of the Company, continued operation of the QF in connection with the utility's system may create or contribute to a system emergency.

INTERCONNECTION REQUIREMENTS (Continued)

The QF owner interconnecting with the Company's distribution system must comply with all requirements for interconnection as established pursuant to Commission rule, in the Company's Rules and Regulations (Rule C) or the Company's Interconnection Procedures contained in its FERC Open Access Transmission Tariff (OATT), as applicable. The Seller will bear full responsibility for the installation and safe operation of the interconnection facilities.

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE PRICING UNDER THE STANDARD PPA

A QF will be eligible to receive pricing under the Standard PPA if the nameplate capacity of the QF, together with any other electric generating facility using the same motive force, owned or controlled by the Same Person(s) or Affiliated Person(s), and located at the Same Site, does not exceed 10 MW. A Community-Based or Family-Owned QF is exempt from these restrictions.

Definition of Community-Based

- a. A community project (or a community sponsored project) must have a recognized and established organization located within the county of the project or within 50 miles of the project that has a genuine role in helping the project be developed and must have some not insignificant continuing role with or interest in the project after it is completed and placed in service.
- b. After excluding the passive investor whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit, the equity (ownership) interests in a community sponsored project must be owned in substantial percentage (80 percent or more) by the following persons (individuals and entities): (i) the sponsoring organization, or its controlled affiliates; (ii) members of the sponsoring organization (if it is a membership organization) or owners of the sponsorship organization (if it is privately owned); (iii) persons who live in the county in which the project is located or who live a county adjoining the county in which the project is located; or (iv) units of local government, charities, or other established nonprofit organizations active either in the county in which the project is located or active in a county adjoining the county in which the project is located.

Definition of Family-Owned

After excluding the ownership interest of the passive investor whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit, five or fewer individuals own 50 percent or more of the equity of the project entity, or fifteen or fewer individuals own 90 percent or more of the project entity. A "look through" rule applies to closely held entities that hold the project entity, so that equity held by LLCs, trusts, estates, corporations, partnerships or other similar entities is considered held by the equity owners of the look through entity. An individual is a natural person. In counting to five or fifteen, spouses or children of an equity owner of the project owner who also have an equity interest are aggregated and counted as a single individual.

SCHEDULE 201 (Continued)

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE PRICING UNDER THE STANDARD PPA (Continued)

Definition of Person(s) or Affiliated Person(s)

As used above, the term "Same Person(s)" or "Affiliated Person(s)" means a natural person or persons or any legal entity or entities sharing common ownership, management or acting jointly or in concert with or exercising influence over the policies or actions of another person or entity. However, two facilities will not be held to be owned or controlled by the Same Person(s) or Affiliated Person(s) solely because they are developed by a single entity.

Furthermore, two facilities will not be held to be owned or controlled by the Same Person(s) or Affiliated Person(s) if such common person or persons is a "passive investor" whose ownership interest in the QF is primarily related to utilizing production tax credits, green tag values and MACRS depreciation as the primary ownership benefit and the facilities at issue are independent family-owned or community-based projects. A unit of Oregon local government may also be a "passive investor" in a community-based project if the local governmental unit demonstrates that it will not have an equity ownership interest in or exercise any control over the management of the QF and that its only interest is a share of the cash flow from the QF, which share will not exceed 20%. The 20% cash flow share limit may only be exceeded for good cause shown and only with the prior approval of the Commission.

Definition of Same Site

For purposes of the foregoing, generating facilities are considered to be located at the same site as the QF for which qualification for pricing under the Standard PPA is sought if they are located within a five-mile radius of any generating facilities or equipment providing fuel or motive force associated with the QF for which qualification for pricing under the Standard PPA is sought.

Definition of Shared Interconnection and Infrastructure

QFs otherwise meeting the above-described separate ownership test and thereby qualified for entitlement to pricing under the Standard PPA will not be disqualified by utilizing an interconnection or other infrastructure not providing motive force or fuel that is shared with other QFs qualifying for pricing under the Standard PPA so long as the use of the shared interconnection complies with the interconnecting utility's safety and reliability standards, interconnection agreement requirements and Prudent Electrical Practices as that term is defined in the interconnecting utility's approved Standard PPA.

OTHER DEFINITIONS

Mid-C Index Price

As used in this schedule, the daily Mid-C Index Price shall be the Day Ahead Intercontinental Exchange ("ICE") for the bilateral OTC market for energy at the Mid-C Physical for Average

SCHEDULE 201 (Continued)

OTHER DEFINITIONS (Continued)

On-Peak Power and Average Off-Peak Power found on the following website: https://www.theice.com/products/OTC/Physical-Energy/Electricity. In the event ICE no longer publishes this index, PGE and the Seller agree to select an alternative successor index representative of the Mid-C trading hub.

Definition of RPS Attributes

As used in this schedule, RPS Attributes means all attributes related to the Net Output generated by the Facility that are required in order to provide PGE with "qualifying electricity," as that term is defined in Oregon's Renewable Portfolio Standard Act, Ore. Rev. Stat. 469A.010, in effect at the time of execution of this Agreement. RPS Attributes do not include Environmental Attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity and not needed to ensure that there are zero net emissions associated with the generation of electricity.

Definition of Environmental Attributes

As used in this schedule, Environmental Attributes shall mean any and all claims, credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical, or other substance to the air, soil or water. Environmental Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil, or water such as (subject to the foregoing) sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; and (2) any avoided emissions of carbon dioxide (CO2), methane (CH4), and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere.

Definition of Resource Sufficiency Period

This is the period from the current year through 2020.

Definition of Resource Deficiency Period

This is the period from 2021 through 2034.

Definition of Renewable Resource Sufficiency Period

This is the period from the current year through 2019.

Definition of Renewable Resource Deficiency Period

This is the period from 2020 through 2034.

SCHEDULE 201 (Concluded)

DISPUTE RESOLUTION

Upon request, the QF will provide the purchasing utility with documentation verifying the ownership, management and financial structure of the QF in reasonably sufficient detail to allow the utility to make an initial determination of whether or not the QF meets the above-described criteria for entitlement to pricing under the Standard PPA.

The QF may present disputes to the Commission for resolution using the following process:

The QF may file a complaint asking the Commission to adjudicate disputes regarding the formation of the standard contract. The QF may not file such a complaint during any 15-day period in which the utility has the obligation to respond, but must wait until the 15-day period has passed.

The utility may respond to the complaint within ten days of service.

The Commission will limit its review to the issues identified in the complaint and response, and utilize a process similar to the arbitration process adopted to facilitate the execution of interconnection agreements among telecommunications carriers. See OAR 860, Division 016. The administrative law judge will not act as an arbitrator.

SPECIAL CONDITIONS

- 1. Delivery of energy by Seller will be at a voltage, phase, frequency, and power factor as specified by the Company.
- 2. If the Seller also receives retail Electricity Service from the Company at the same location, any payments under this schedule will be credited to the Seller's retail Electricity Service bill. At the option of the Customer, any net credit over \$10.00 will be paid by check to the Customer.
- 3. Unless required by state or federal law, if the 1978 Public Utility Regulatory Policies Act (PURPA) is repealed, PPAs entered into pursuant to this schedule will not terminate prior to the Standard or Negotiated PPA's termination date.

TERM OF AGREEMENT

Not less than one year and not to exceed 20 years.

FEDERAL ENERGY REGULATORY COMMISSION WASHINGTON, DC

OMB Control # 1902-0075 Expiration 06/30/2019

Form 556 Certification of Qualifying Facility (QF) Status for a Small Power Production or Cogeneration Facility

General

Questions about completing this form should be sent to Form556@ferc.gov. Information about the Commission's QF program, answers to frequently asked questions about QF requirements or completing this form, and contact information for QF program staff are available at the Commission's QF website, www.ferc.gov/QF. The Commission's QF website also provides links to the Commission's QF regulations (18 C.F.R. § 131.80 and Part 292), as well as other statutes and orders pertaining to the Commission's QF program.

Who Must File

Any applicant seeking QF status or recertification of QF status for a generating facility with a net power production capacity (as determined in lines 7a through 7g below) greater than 1000 kW must file a self-certification or an application for Commission certification of QF status, which includes a properly completed Form 556. Any applicant seeking QF status for a generating facility with a net power production capacity 1000 kW or less is exempt from the certification requirement, and is therefore not required to complete or file a Form 556. See 18 C.F.R. § 292.203.

How to Complete the Form 556

This form is intended to be completed by responding to the items in the order they are presented, according to the instructions given. If you need to back-track, you may need to clear certain responses before you will be allowed to change other responses made previously in the form. If you experience problems, click on the nearest help button (1) for assistance, or contact Commission staff at Form556@ferc.gov.

Certain lines in this form will be automatically calculated based on responses to previous lines, with the relevant formulas shown. You must respond to all of the previous lines within a section before the results of an automatically calculated field will be displayed. If you disagree with the results of any automatic calculation on this form, contact Commission staff at Form556@ferc.gov to discuss the discrepancy before filing.

You must complete all lines in this form unless instructed otherwise. Do not alter this form or save this form in a different format, incomplete or altered forms, or forms saved in formats other than PDF, will be rejected.

How to File a Completed Form 556

Applicants are required to file their Form 556 electronically through the Commission's eFiling website (see instructions on page 2). By filing electronically, you will reduce your filing burden, save paper resources, save postage or courier charges, help keep Commission expenses to a minimum, and receive a much faster confirmation (via an email containing the docket number assigned to your facility) that the Commission has received your filing.

If you are simultaneously filing both a waiver request and a Form 556 as part of an application for Commission certification, see the "Walver Requests" section on page 3 for more information on how to file.

Paperwork Reduction Act Notice

This form is approved by the Office of Management and Budget. Compliance with the information requirements established by the FERC Form No. 556 is required to obtain or maintain status as a QF. See 18 C.F.R. § 131.80 and Part 292. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The estimated burden for completing the FERC Form No. 556, including gathering and reporting information, is as follows: 3 hours for self-certification of a small power production facility, 8 hours for self-certifications of a cogeneration facility, 6 hours for an application for Commission certification of a small power production facility, and 50 hours for an application for Commission certification of a cogeneration facility. Send comments regarding this burden estimate or any aspect of this collection of information, including suggestions for reducing this burden, to the following: Information Clearance Officer, Office of the Executive Director (ED-32), Federal Energy Regulatory Commission, 888 First Street N.E., Washington, DC 20426 (DataClearance@ferc.gov); and Desk Officer for FERC, Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (oira_submission@omb.eop.gov), include the Control No. 1902-0075 in any correspondence.

Electronic Filing (eFiling)

To electronically file your Form 556, visit the Commission's QF website at www.ferc.gov/QF and click the eFiling link.

If you are eFiling your first document, you will need to register with your name, email address, mailing address, and phone number. If you are registering on behalf of an employer, then you will also need to provide the employer name, alternate contact name, alternate contact phone number and and alternate contact email.

Once you are registered, log in to eFiling with your registered email address and the password that you created at registration. Follow the Instructions. When prompted, select one of the following QF-related filing types, as appropriate, from the Electric or General filing category.

Filing category	Filling Type as listed in eFilling	Description
	(Fee) Application for Commission Cert. as Cogeneration QF	Use to submit an application for Commission certification or Commission recertification of a cogeneration facility as a QF.
	(Fee) Application for Commission Cert. as Small Power QF	Use to submit an application for Commission certification or Commission recertification of a small power production facility as a QF.
	Self-Certification Notice (QF, EG, FC)	Use to submit a notice of self- certification of your facility (cogeneration or small power production) as a QF.
Electric	Self-Recertification of Qualifying Facility (QF)	Use to submit a notice of self- recertification of your facility (cogeneration or small power production) as a QF.
	Supplemental Information or Request	Use to correct or supplement a Form 556 that was submitted with errors or omissions, or for which Commission staff has requested additional information. Do not use this filling type to report new changes to a facility or its ownership; rather, use a self-recertification or Commission recertification to report such changes.
General	(Fee) Petition for Declaratory Order (not under FPA Part 1)	Use to submit a petition for declaratory order granting a walver of Commission QF regulations pursuant to 18 C.F.R. §§ 292.204(a) (3) and/or 292.205(c). A Form 556 is not required for a petition for declaratory order unless Commission recertification is being requested as part of the petition.

You will be prompted to submit your filing fee, if applicable, during the electronic submission process. Filing fees can be paid via electronic bank account debit or credit card.

During the eFiling process, you will be prompted to select your file(s) for upload from your computer.

FERC Form 556

Page 3 - Instructions

Filing Fee

No filing fee is required if you are submitting a self-certification or self-recertification of your facility as a QF pursuant to 18 C.F.R. § 292.207(a).

A filing fee is required if you are filing either of the following:

(1) an application for Commission certification or recertification of your facility as a QF pursuant to 18 C.F.R. § 292.207(b), or (2) a petition for declaratory order granting waiver pursuant to 18 C.F.R. §§ 292.204(a)(3) and/or 292.205(c).

The current fees for applications for Commission certifications and petitions for declaratory order can be found by visiting the Commission's QF website at www.ferc.gov/QF and clicking the Fee Schedule link.

You will be prompted to submit your filing fee, if applicable, during the electronic filing process described on page 2.

Required Notice to Utilities and State Regulatory Authorities

Pursuant to 18 C.F.R. § 292.207(a)(ii), you must provide a copy of your self-certification or request for Commission certification to the utilities with which the facility will interconnect and/or transact, as well as to the State regulatory authorities of the states in which your facility and those utilities reside. Links to information about the regulatory authorities in various states can be found by visiting the Commission's QF website at www.ferc.gov/QF and clicking the Notice Requirements link.

What to Expect From the Commission After You File

An applicant filing a Form 556 electronically will receive an email message acknowledging receipt of the filing and showing the docket number assigned to the filing. Such email is typically sent within one business day, but may be delayed pending confirmation by the Secretary of the Commission of the contents of the filing.

An applicant submitting a self-certification of QF status should expect to receive no documents from the Commission, other than the electronic acknowledgement of receipt described above. Consistent with its name, a self-certification is a certification by the applicant itself that the facility meets the relevant requirements for QF status, and does not involve a determination by the Commission as to the status of the facility. An acknowledgement of receipt of a self-certification, in particular, does not represent a determination by the Commission with regard to the QF status of the facility. An applicant self-certifying may, however, receive a rejection, revocation or deficiency letter if its application is found, during periodic compliance reviews, not to comply with the relevant requirements.

An applicant submitting a request for Commission certification will receive an order either granting or denying certification of QF status, or a letter requesting additional information or rejecting the application. Pursuant to 18 C.F.R. § 292.207(b)(3), the Commission must act on an application for Commission certification within 90 days of the later of the filing date of the application or the filing date of a supplement, amendment or other change to the application.

Waiver Requests

18 C.F.R. § 292.204(a)(3) allows an applicant to request a waiver to modify the method of calculation pursuant to 18 C.F.R. § 292.204(a)(2) to determine if two facilities are considered to be located at the same site, for good cause. 18 C.F.R. § 292.205(c) allows an applicant to request waiver of the requirements of 18 C.F.R. §§ 292.205(a) and (b) for operating and efficiency upon a showing that the facility will produce significant energy savings. A request for waiver of these requirements must be submitted as a petition for declaratory order, with the appropriate filling fee for a petition for declaratory order. Applicants requesting Commission recertification as part of a request for waiver of one of these requirements should electronically submit their completed Form 556 along with their petition for declaratory order, rather than filling their Form 556 as a separate request for Commission recertification. Only the filling fee for the petition for declaratory order must be paid to cover both the waiver request and the request for recertification if such requests are made simultaneously.

18 C.F.R. § 292.203(d)(2) allows an applicant to request a walver of the Form 556 filling requirements, for good cause. Applicants filling a petition for declaratory order requesting a walver under 18 C.F.R. § 292.203(d)(2) do not need to complete or submit a Form 556 with their petition.

Page 4 - Instructions

Geographic Coordinates

If a street address does not exist for your facility, then line 3c of the Form 556 requires you to report your facility's geographic coordinates (latitude and longitude). Geographic coordinates may be obtained from several different sources. You can find links to online services that show latitude and longitude coordinates on online maps by visiting the Commission's QF webpage at www.ferc.gov/OF and clicking the Geographic Coordinates link. You may also be able to obtain your geographic coordinates from a GPS device, Google Earth (available free at https://earth.google.com), a property survey, various engineering or construction drawings, a property deed, or a municipal or county map showing property lines.

Filing Privileged Data or Critical Energy Infrastructure Information in a Form 556

The Commission's regulations provide procedures for applicants to either (1) request that any information submitted with a Form 556 be given privileged treatment because the information is exempt from the mandatory public disclosure requirements of the Freedom of Information Act, 5 U.S.C. § 552, and should be withheld from public disclosure; or (2) identify any documents containing critical energy infrastructure information (CEII) as defined in 18 C.F.R. § 388.113 that should not be made public.

If you are seeking privileged treatment or CEII status for any data in your Form 556, then you must follow the procedures in 18 C.F.R. § 388.112. See www.ferc.gov/help/filling-guide/file-ceii.asp for more information.

Among other things (see 18 C.F.R. § 388.112 for other requirements), applicants seeking privileged treatment or CEII status for data submitted in a Form 556 must prepare and file both (1) a complete version of the Form 556 (containing the privileged and/or CEII data), and (2) a public version of the Form 556 (with the privileged and/or CEII data redacted). Applicants preparing and filing these different versions of their Form 556 must indicate below the security designation of this version of their document. If you are *not* seeking privileged treatment or CEII status for any of your Form 556 data, then you should not respond to any of the Items on this page.

The eFiling process described on page 2 will allow you to identify which versions of the electronic documents you submit are public, privileged and/or CEII. The filenames for such documents should begin with "Public", "Priv", or "CEII", as applicable, to clearly indicate the security designation of the file. Both versions of the Form 556 should be unaltered PDF copies of the Form 556, as available for download from www.ferc.gov/QE. To redact data from the public copy of the submittal, simply omit the relevant data from the Form. For numerical fields, leave the redacted fields blank. For text fields, complete as much of the field as possible, and replace the redacted portions of the field with the word "REDACTED" in brackets. Be sure to identify above all fields which contain data for which you are seeking non-public status.

The Commission is not responsible for detecting or correcting filer errors, including those errors related to security designation. If your documents contain sensitive information, make sure they are filed using the proper security designation.

FEDERAL ENERGY REGULATORY COMMISSION WASHINGTON, DC

OMB Control # 1902-0075 Expiration 06/30/2019

Form 556 Certification of Qualifying Facility (QF) Status for a Small Power Production or Cogeneration Facility

		1b Applicant street address 808 Travis Street #700						
	1c City Houston		1d State/province TX					
	1e Postal code 77002	1f Country (If not United States)	1g Telephone number 713–265–0350					
	1h Has the Instant facil	ity ever previously been certified as a Q	F? Yes N	No 🛛				
	1i If yes, provide the do	ocket number of the last known QF filin	g pertaining to th	nis facility: QF	O			
	1j Under which certific	ation process is the applicant making th	nis filing?					
_	Notice of self-certing (see note below)	Ification \Box^A_{fe}	pplication for Co ee; see "Filing Fee	ommission certification (requires filing e" section on page 3)				
Application Information	QF status. A notice notice of self-certifl	Note: a notice of self-certification is a notice by the applicant itself that its facility complies with the requirements for QF status. A notice of self-certification does not establish a proceeding, and the Commission does not review a notice of self-certification to verify compliance. See the "What to Expect From the Commission After You File" section on page 3 for more information.						
nfc	1k What type(s) of QF status is the applicant seeking for its facility? (check all that apply)							
l nc	Qualifying small power production facility status							
icatic	11 What is the purpose and expected effective date(s) of this filling? Original certification; facility expected to be installed by 3/1/20 and to begin operation on 3/31/20							
Appl	[Change(s) to a previously certified facility to be effective on							
	[] Name change and/or other administrative change(s)							
	[Change in ownership							
	[] Change(s) affecting plant equipment, fuel use, power production capacity and/or cogeneration thermal output							
	Supplement or correction to a previous filing submitted on (describe the supplement or correction in the Miscellaneous section starting on page 19)							
	1m If any of the following three statements is true, check the box(es) that describe your situation and complete the form to the extent possible, explaining any special circumstances in the Miscellaneous section starting on page 19.							
	The instant facility complies with the Commission's QF requirements by virtue of a walver of certain regulations previously granted by the Commission in an order dated orders in the Miscellaneous section starting on page 19)							
	The Instant facility would comply with the Commission's QF requirements if a petition for waiver submitted concurrently with this application is granted							
	☐ employment of	lity complies with the Commission's reg	contemplated b	s special circumstances, such as the y the structure of this form, that make lescribe in Misc, section starting on p. 19)				

Page 6 - All Facilities FERC Form 556 2b Telephone number 2a Name of contact person 713-265-0350 Leslie A. Freiman 2c Which of the following describes the contact person's relationship to the applicant? (check one) Employee, owner or partner of applicant authorized to represent the applicant Applicant (self) Contact Information M Employee of a company affiliated with the applicant authorized to represent the applicant on this matter Lawyer, consultant, or other representative authorized to represent the applicant on this matter 2d Company or organization name (if applicant is an individual, check here and skip to line 2e) EDP Renewables North America LLC 2e Street address (if same as Applicant, check here and skip to line 3a) 2a State/province 2f City 21 Country (if not United States) 2h Postal code 3a Facility name Facility Identification and Location Blue Marmot VIII 3b Street address (if a street address does not exist for the facility, check here and skip to line 3c) 3c Geographic coordinates: If you indicated that no street address exists for your facility by checking the box in line 3b, then you must specify the latitude and longitude coordinates of the facility in degrees (to three decimal places). Use the following formula to convert to decimal degrees from degrees, minutes and seconds: decimal degrees = degrees + (minutes/60) + (seconds/3600). See the "Geographic Coordinates" section on page 4 for help. If you provided a street address for your facility in line 3b, then specifying the geographic coordinates below is optional. North (+) ☐ East (+) 42,197 degrees Latitude 120.556 degrees Longitude South (-) ---3d City (if unincorporated, check here and enter nearest city) 3e State/province Lakeview 3g Country (if not United States) 3f County (or check here for independent city) Identify the electric utilities that are contemplated to transact with the facility. **Iransacting Utilities** 4a Identify utility interconnecting with the facility PacifiCorp (Pacific Power) 4b Identify utilities providing wheeling service or check here if none PacifiCorp (Pacific Power) f 4c Identify utilities purchasing the useful electric power output or check here if none lacksquarePortland General Electric Company 4d Identify utilities providing supplementary power, backup power, maintenance power, and/or interruptible power service or check here if none

PacifiCorp (Pacific Power)

FEI	FERC Form 556 Page 7 - All Facilities						
	5a Direct ownership as of effective date or operation date: Identify all direct owners of the facility holding at least percent equity interest. For each identified owner, also (1) indicate whether that owner is an electric utility, as defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or a holding company, as defined in section 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(8)), and (2) for owners which are elutilities or holding companies, provide the percentage of equity interest in the facility held by that owner. If no direct owners hold at least 10 percent equity interest in the facility, then provide the required information for						
	two direct owners with the largest equity interest in the facility.	Electric u holdi	ng	If Yes, % equity			
	Full legal names of direct owners	comp	any	interest			
	1) Blue Marmot VIII LLC	Yes 🔀	No 🗌	100 %			
	2)	Yes 🔲	No 🔲				
	3)	Yes 🗌	No 🔲				
	4)	Yes 🗌	No 🗌				
	5)	Yes 🗌	No 🗌				
	6)	Yes 🔲	No 🗌	8			
	7)	Yes 🗌	No 🗌				
	8)	Yes 🗌	No 🔲				
on	9)	Yes 🗌	No 🗌				
Operation	10)	Yes 🔲	No 🔲	%			
Jeľ	Check here and continue in the Miscellaneous section starting on page 19 if additional space is needed						
Ownership and	5b Upstream (i.e., indirect) ownership as of effective date or operation date: Identify all of the facility that both (1) hold at least 10 percent equity interest in the facility, and (defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or holding comp 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(8)). Also equity interest in the facility held by such owners. (Note that, because upstream own another, total percent equity interest reported may exceed 100 percent.)	anies, as de provide the	fined in : percenta	section ge of			
Wne	Check here If no such upstream owners exist.			0/ parettre			
0	Full legal names of electric utility or holding company upstream own	ers	******	% equity interest			
	1) EDP Renewables North America LLC		-	100%			
	2)						
	3)			~			
	4)			*			
	5)			<u></u> &			
	6)	, , , , , , , , , , , , , , , , , , , ,		 %			
	7)						
	8)			£			
	9)			 ક			
	10)		·····	<u> </u> 4			
	Check here and continue in the Miscellaneous section starting on page 19 if add	itional space	e is need	ed			
	5c Identify the facility operator						
	Blue Marmot VIII LLC			The same of the sa			

Indicate the maximum gross and maximum net electric power production capacity of the facility at the point(s) of delivery by completing the worksheet below. Respond to all Items. If any of the parasitic loads and/or losses identified lines 7b through 7e are negligible, enter zero for those lines.				
7a The maximum gross power production capacity at the terminals of the individual generator(s) under the most favorable anticipated design conditions	10,000 kW			
7b Parasitic station power used at the facility to run equipment which is necessary and integral to the power production process (boiler feed pumps, fans/blowers, office or maintenance buildings directly related to the operation of the power generating facility, etc.). If this facility includes non-power production processes (for instance, power consumed by a cogeneration facility's thermal host), do not include any power consumed by the non-power production activities in your reported parasitic station power.	s kw			
7c Electrical losses in interconnection transformers	176 kW			
7d Electrical losses in AC/DC conversion equipment, if any	10 kW			
7e Other interconnection losses in power lines or facilities (other than transformers and AC/DC conversion equipment) between the terminals of the generator(s) and the point of interconnection with the utility	240 kW			
7f Total deductions from gross power production capacity = 7b + 7c + 7d + 7e	431.0 kW			
7g Maximum net power production capacity = 7a - 7f	9,569.0 kW			

Phescription of facility and primary components: Describe the facility and its operation. Identify all bollers, heat recovery steam generators, prime movers (any mechanical equipment driving an electric generator), electrical generators, photovoltaic solar equipment, fuel cell equipment and/or other primary power generation equipment used in the facility. Descriptions of components should include (as applicable) specifications of the nominal capacities for mechanical output, electrical output, or steam generation of the identified equipment. For each piece of equipment identified, clearly indicate how many pieces of that type of equipment are included in the plant, and which components are normally operating or normally in standby mode. Provide a description of how the components operate as a system. Applicants for cogeneration facilities do not need to describe operations of systems that are clearly depicted on and easily understandable from a cogeneration facility's attached mass and heat balance diagram; however, such applicants should provide any necessary description needed to understand the sequential operation of the facility depicted in their mass and heat balance diagram. If additional space is needed, continue in the Miscellaneous section starting on page 19.

The facility will be a solar FV plant consisting of 39,324 polycrystalline modules of nominal 335W rating each. Total plant rating will be 13.174MWdc/10MWac. Modules will be mounted to single-axis trackers.

Central inverter stations will be located at intermediate points in the PV field. Modules will be evenly distributed to the inverter stations. The total inverter nameplate rating will be 10.0MWac. Each inverter will be directly coupled to a 34.5kV step-up transformer. The transformers will be connected to a 34.5kV AC collection system, which will feed into the plant switchgear.

The plant switchgear will feed a 34.5kV transmission line, which will run overhead approximately 11.1 miles to the PacifiCorp Mile-Ri Substation.

Inside the Mile-Hi Substation, the transmission line will connect to a new bay containing a facility-owned 34.5kV/115kV GSU transformer, associated breakers, switching, bus, and controls.

The facility-owned components at Mile-Hi substation are considered part of the self-certified qualifying facility.



Information Required for Small Power Production Facility

if you indicated in line 1k that you are seeking qualifying small power production facility status for your facility, then you must respond to the items on this page. Otherwise, skip page 10,

Pursuant to 18 C.F.R. § 292.204(a), the power production capacity of any small power production facility, together with the power production capacity of any other small power production facilities that use the same energy resource, are owned by the same person(s) or its affiliates, and are located at the same site, may not exceed 80 megawatts. To demonstrate compliance with this size limitation, or to demonstrate that your facility is exempt from this size limitation under the Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990 (Pub. L. 101-575, 104 Stat. 2834 (1990) as amended by Pub. L. 102-46, 105 Stat. 249 (1991)), respond to lines 8a through 8e below (as applicable). 8a Identify any facilities with electrical generating equipment located within 1 mile of the electrical generating equipment of the instant facility, and for which any of the entities identified in lines 5a or 5b, or their affiliates, holds at least a 5 percent equity interest. Certification of Compliance Check here if no such facilities exist. 🖂 Maximum net power Root docket # with Size Limitations Facility location Common owner(s) production capacity (if any) (city or county, state) k₩ QF kW 2) QF kW 3) QF____ Check here and continue in the Miscellaneous section starting on page 19 If additional space is needed 8b The Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990 (Incentives Act) provides exemption from the size limitations in 18 C.F.R. § 292.204(a) for certain facilities that were certified prior to 1995. Are you seeking exemption from the size limitations in 18 C.F.R. § 292.204(a) by virtue of the incentives Act? No (skip lines 8c through 8e) Yes (continue at line 8c below) 8c Was the original notice of self-certification or application for Commission certification of the facility filed on or before December 31, 19947 Yes 🗍 No 📋 8d Dld construction of the facility commence on or before December 31, 1999? Yes 🗍 No 🧻 8e If you answered No in line 8d, indicate whether reasonable diligence was exercised toward the completion of the facility, taking into account all factors relevant to construction? Yes 📋 No 📋 If you answered Yes, provide a brief narrative explanation in the Miscellaneous section starting on page 19 of the construction timeline (in particular, describe why construction started so long after the facility was certified) and the diligence exercised toward completion of the facility. Pursuant to 18 C.F.R. § 292.204(b), qualifying small power production facilities may use fossil fuels, in minimal with Fuel Use Requirements Certification of Compliance amounts, for only the following purposes: ignition; start-up; testing; flame stabilization; control use; alleviation or prevention of unanticipated equipment outages; and alleviation or prevention of emergencies, directly affecting the public health, safety, or welfare, which would result from electric power outages. The amount of fossil fuels used for these purposes may not exceed 25 percent of the total energy input of the facility during the 12-month period beginning with the date the facility first produces electric energy or any calendar year thereafter. 9a Certification of compliance with 18 C.F.R. § 292,204(b) with respect to uses of fossil fuel: Applicant certifies that the facility will use fossil fuels exclusively for the purposes listed above, 9b Certification of compliance with 18 C.F.R. § 292,204(b) with respect to amount of fossil fuel used annually: Applicant certifies that the amount of fossil fuel used at the facility will not, in aggregate, exceed 25 percent of the total energy input of the facility during the 12-month period beginning with the date the facility first produces electric energy or any calendar year thereafter.



Information Required for Cogeneration Facility

If you indicated in line 1k that you are seeking qualifying cogeneration facility status for your facility, then you must respond

to the ite	ems on pages 11 through	13. Otherwise, skip pages 11 through 13.		
	Pursuant to 18 C.F.R. § 292.202(c), a cogeneration facility produces electric energy and forms of useful thermal energy (such as heat or steam) used for industrial, commercial, heating, or cooling purposes, through the sequential use of energy. Pursuant to 18 C.F.R. § 292.202(s), "sequential use" of energy means the following: (1) for a topping-cycle cogeneration facility, the use of reject heat from a power production process in sufficient amounts in a thermal application or process to conform to the requirements of the operating standard contained in 18 C.F.R. § 292.205(a); or (2) for a bottoming-cycle cogeneration facility, the use of at least some reject heat from a thermal application or process for power production.			
	10a What type(s) of cog	eneration technology does the facility represent? (check all that apply)		
	Topping-cycle			
	other requirements balance diagram de meet certain requir	te the sequential operation of the cogeneration process, and to support compliance with is such as the operating and efficiency standards, include with your filing a mass and heat epicting average annual operating conditions. This diagram must include certain items and ements, as described below. You must check next to the description of each requirement at you have complied with these requirements.		
•	Check to certify compliance with Indicated requirement	Requirement		
General Cogeneration Information		Diagram must show orientation within system piping and/or ducts of all prime movers, heat recovery steam generators, boilers, electric generators, and condensers (as applicable), as well as any other primary equipment relevant to the cogeneration process.		
		Any average annual values required to be reported in lines 10b, 12a, 13a, 13b, 13d, 13f, 14a, 15b, 15d and/or 15f must be computed over the anticipated hours of operation.		
		Diagram must specify all fuel inputs by fuel type and average annual rate in Btu/h. Fuel for supplementary firing should be specified separately and clearly labeled. All specifications of fuel inputs should use lower heating values.		
sue :		Diagram must specify average gross electric output in kW or MW for each generator.		
Ge		Diagram must specify average mechanical output (that is, any mechanical energy taken off of the shaft of the prime movers for purposes not directly related to electric power generation) in horsepower, if any. Typically, a cogeneration facility has no mechanical output.		
		At each point for which working fluid flow conditions are required to be specified (see below), such flow condition data must include mass flow rate (in lb/h or kg/s), temperature (in °F, R, °C or K), absolute pressure (in psia or kPa) and enthalpy (in Btu/lb or kJ/kg). Exception: For systems where the working fluid is <i>liquid only</i> (no vapor at any point in the cycle) and where the type of liquid and specific heat of that liquid are clearly indicated on the diagram or in the Miscellaneous section starting on page 19, only mass flow rate and temperature (not pressure and enthalpy) need be specified. For reference, specific heat at standard conditions for pure liquid water is approximately 1.002 Btu/ (lb*R) or 4.195 kJ/(kg*K).		
		Diagram must specify working fluid flow conditions at input to and output from each steam turbine or other expansion turbine or back-pressure turbine.		
		Diagram must specify working fluid flow conditions at delivery to and return from each thermal application.		
		Diagram must specify working fluid flow conditions at make-up water inputs.		









	EPAct 2005 cogeneration facilities: The Energy Policy Act of 2005 (EPAct 2005) established a new section 210(n) of the Public Utility Regulatory Policies Act of 1978 (PURPA), 16 USC 824a-3(n), with additional requirements for any qualifying cogeneration facility that (1) is seeking to self electric energy pursuant to section 210 of PURPA and (2) was either not a cogeneration facility on August 8, 2005, or had not filed a self-certification or application for Commission certification of QF status on or before February 1, 2006. These requirements were implemented by the Commission in 18 C.F.R. § 292.205(d). Complete the lines below, carefully following the instructions, to demonstrate whether these additional requirements apply to your cogeneration facility and, if so, whether your facility complies with such requirements.	
	11a Was your facility operating as a qualifying cogeneration facility on or before August 8, 2005? Yes No	
	11b Was the initial filing seeking certification of your facility (whether a notice of self-certification or an application for Commission certification) filed on or before February 1, 2006? Yes No	
a vo	If the answer to either line 11a or 11b is Yes, then continue at line 11c below. Otherwise, if the answers to both lines 11a and 11b are No, skip to line 11e below.	
EPAct 2005 Requirements for Fundamental Use of Energy Output from Cogeneration Facilities	11c With respect to the design and operation of the facility, have any changes been implemented on or after February 2, 2006 that affect general plant operation, affect use of thermal output, and/or increase net power production capacity from the plant's capacity on February 1, 20067	
nen F	Yes (continue at line 11d below)	
-undar eratior	No. Your facility is not subject to the requirements of 18 C.F.R. § 292.205(d) at this time. However, it may be subject to to these requirements in the future if changes are made to the facility. At such time, the applicant would need to recertify the facility to determine eligibility. Skip lines 11d through 11j.	
for l	11d Does the applicant contend that the changes identified in line 11c are not so significant as to make the facility a "new" cogeneration facility that would be subject to the 18 C.F.R. § 292.205(d) cogeneration requirements?	
ements rom C	Yes. Provide in the Miscellaneous section starting on page 19 a description of any relevant changes made to [] the facility (including the purpose of the changes) and a discussion of why the facility should not be considered a "new" cogeneration facility in light of these changes. Skip lines 11e through 11j.	
equire ıtput fı	No. Applicant stipulates to the fact that it is a "new" cogeneration facility (for purposes of determining the policability of the requirements of 18 C.F.R. § 292.205(d)) by virtue of modifications to the facility that were initiated on or after February 2, 2006. Continue below at line 11e.	
)5. VO	11e Will electric energy from the facility be sold pursuant to section 210 of PURPA?	
:t 20(nerg)	Yes. The facility is an EPAct 2005 cogeneration facility. You must demonstrate compliance with 18 C.F.R. § 292,205(d)(2) by continuing at line 11f below.	
EPAct of En	No. Applicant certifies that energy wili not be sold pursuant to section 210 of PURPA. Applicant also certifies its understanding that it must recertify its facility in order to determine compliance with the requirements of 18 C.F.R. § 292.205(d) before selling energy pursuant to section 210 of PURPA in the future. Skip lines 11f through 11j.	
	11f Is the net power production capacity of your cogeneration facility, as indicated in line 7g above, less than or equal to 5,000 kW?	
	Yes, the net power production capacity is less than or equal to 5,000 kW. 18 C.F.R. § 292.205(d)(4) provides a rebuttable presumption that cogeneration facilities of 5,000 kW and smaller capacity comply with the requirements for fundamental use of the facility's energy output in 18 C.F.R. § 292.205(d)(2). Applicant certifies its understanding that, should the power production capacity of the facility increase above 5,000 kW, then the facility must be recertified to (among other things) demonstrate compliance with 18 C.F.R. § 292.205(d)(2). Skip lines 11g through 11j.	
	No, the net power production capacity is greater than 5,000 kW. Demonstrate compliance with the requirements for fundamental use of the facility's energy output in 18 C.F.R. § 292.205(d)(2) by continuing on the next page at line 11g.	

Lines 11g through 11k below guide the applicant through the process of demonstrating compliance with the requirements for "fundamental use" of the facility's energy output. 18 C.F.R. § 292.205(d)(2). Only respond to the lines on this page if the instructions on the previous page direct you to do so. Otherwise, skip this page.

18 C.F.R. § 292,205(d)(2) requires that the electrical, thermal, chemical and mechanical output of an EPAct 2005 cogeneration facility is used fundamentally for industrial, commercial, residential or institutional purposes and is not intended fundamentally for sale to an electric utility, taking into account technological, efficiency, economic, and variable thermal energy requirements, as well as state laws applicable to sales of electric energy from a qualifying facility to its host facility. If you were directed on the previous page to respond to the items on this page, then your facility is an EPAct 2005 cogeneration facility that is subject to this "fundamental use" requirement.

The Commission's regulations provide a two-pronged approach to demonstrating compliance with the requirements for fundamental use of the facility's energy output. First, the Commission has established in 18 C.F.R. § 292.205(d)(3) a "fundamental use test" that can be used to demonstrate compliance with 18 C.F.R. § 292.205(d)(2). Under the fundamental use test, a facility is considered to comply with 18 C.F.R. § 292.205(d)(2) if at least 50 percent of the facility's total annual energy output (including electrical, thermal, chemical and mechanical energy output) is used for industrial, commercial, residential or institutional purposes.

Second, an applicant for a facility that does not pass the fundamental use test may provide a narrative explanation of and support for its contention that the facility nonetheless meets the requirement that the electrical, thermal, chemical and mechanical output of an EPAct 2005 cogeneration facility is used fundamentally for industrial, commercial, residential or institutional purposes and is not intended fundamentally for sale to an electric utility, taking into account technological, efficiency, economic, and variable thermal energy requirements, as well as state laws applicable to sales of electric energy from a qualifying facility to its host facility.

Complete lines 11g through 11j below to determine compliance with the fundamental use test in 18 C.F.R. § 292.205(d)(3). Complete lines 11g through 11j even if you do not intend to rely upon the fundamental use test to demonstrate compliance with 18 C.F.R. § 292.205(d)(2).

11g Amount of electrical, thermal, chemical and mechanical energy output (net of internal generation plant losses and parasitic loads) expected to be used annually for industrial, commercial, residential or institutional purposes and not sold to an electric utility	MWh
11h Total amount of electrical, thermal, chemical and mechanical energy expected to be sold to an electric utility	MWh
11i Percentage of total annual energy output expected to be used for industrial, commercial, residential or institutional purposes and not sold to a utility = 100 * 11q /(11g + 11h)	0 %

11j is the response in line 11i greater than or equal to 50 percent?

Yes, Your facility complies with 18 C.F.R. § 292,205(d)(2) by virtue of passing the fundamental use test provided in 18 C.F.R. § 292,205(d)(3). Applicant certifies its understanding that, if it is to rely upon passing the fundamental use test as a basis for complying with 18 C.F.R. § 292,205(d)(2), then the facility must comply with the fundamental use test both in the 12-month period beginning with the date the facility first produces electric energy, and in all subsequent calendar years.

No. Your facility does not pass the fundamental use test. Instead, you must provide in the Miscellaneous section starting on page 19 a narrative explanation of and support for why your facility meets the requirement that the electrical, thermal, chemical and mechanical output of an EPAct 2005 cogeneration facility is used fundamentally for industrial, commercial, residential or institutional purposes and is not intended fundamentally for sale to an electric utility, taking into account technological, efficiency, economic, and variable thermal energy requirements, as well as state laws applicable to sales of electric energy from a QF to its host facility. Applicants providing a narrative explanation of why their facility should be found to comply with 18 C.F.R. § 292.205(d)(2) in spite of non-compliance with the fundamental use test may want to review paragraphs 47 through 61 of Order No. 671 (accessible from the Commission's QF website at www.ferc.gov/QF), which provide discussion of the facts and circumstances that may support their explanation. Applicant should also note that the percentage reported above will establish the standard that that facility must comply with, both for the 12-month period beginning with the date the facility first produces electric energy, and in all subsequent calendar years. See Order No. 671 at paragraph 51. As such, the applicant should make sure that it reports appropriate values on lines 11g and 11h above to serve as the relevant annual standard, taking into account expected variations in production conditions.



Information Required for Topping-Cycle Cogeneration Facility

If you indicated in line 10a that you	r facility represents topping-cycle cogeneration technology, then you must respond to
the items on pages 14 and 15 Oth	

The thermal energy output of a topping-cycle cogeneration facility is the net energy made available to an industrial or commercial process or used in a heating or cooling application. Pursuant to sections 292.202(c), (d) and (h) of the Commission's regulations (18 C.F.R. §§ 292.202(c), (d) and (h)), the thermal energy output of a qualifying topping-cycle cogeneration facility must be useful. In connection with this requirement, describe the thermal output of the topping-cycle cogeneration facility by responding to lines 12a and 12b below.

12a Identify and describe each thermal host, and specify the annual average rate of thermal output made available to each host for each use. For hosts with multiple uses of thermal output, provide the data for each use in separate rows.
Average annual rate of

thermal output
attributable to use (net of

Name of entity (thermal host)
Thermal host's relationship to facility;
taking thermal output
Thermal host's use of thermal output
return or make-up water)

	taking thermal output	Highlightiost a use of inclination but	record or many ap in
		Select thermal host's relationship to facility	
1)		Select thermal host's use of thermal output	Btu/h
		Select thermal host's relationship to facility	
2)		Select thermal host's use of thermal output	Btu/h
		Select thermal host's relationship to facility	
3)		Select thermal host's use of thermal output	Btu/h
4)		Select thermal host's relationship to facility	
		Select thermal host's use of thermal output	Btu/h
\		Select thermal host's relationship to facility	
5)		Select thermal host's use of thermal output	Btu/h
6)		Select thermal host's relationship to facility	
		Select thermal host's use of thermal output	Btu/h

Check here and continue in the Miscellaneous section starting on page 19 if additional space is needed

12b Demonstration of usefulness of thermal output: At a minimum, provide a brief description of each use of the thermal output identified above. In some cases, this brief description is sufficient to demonstrate usefulness. However, if your facility's use of thermal output is not common, and/or if the usefulness of such thermal output is not reasonably clear, then you must provide additional details as necessary to demonstrate usefulness. Your application may be rejected and/or additional information may be required if an insufficient showing of usefulness is made. (Exception: If you have previously received a Commission certification approving a specific use of thermal output related to the instant facility, then you need only provide a brief description of that use and a reference by date and docket number to the order certifying your facility with the indicated use. Such exemption may not be used if any change creates a material deviation from the previously authorized use.) If additional space is needed, continue in the Miscellaneous section starting on page 19.



ERC F	rm 556	J 1	Cycle Cogeneration racinities	_	
	Applicants for facilities representing topping-cycle technology must demonstrate compliance with the topping-cycle operating standard and, if applicable, efficiency standard. Section 292.205(a)(1) of the Commission's regulations (18 C.F.R. § 292.205(a)(1)) establishes the operating standard for topping-cycle cogeneration facilities: the useful thermal energy output must be no less than 5 percent of the total energy output. Section 292.205(a)(2) (18 C.F.R. § 292.205(a)(2)) establishes the efficiency standard for topping-cycle cogeneration facilities for which installation commenced on or after March 13, 1980: the useful power output of the facility plus one-half the useful thermal energy output must (A) be no less than 42.5 percent of the total energy input of natural gas and oil to the facility; and (B) if the useful thermal energy output is less than 15 percent of the total energy output of the facility, be no less than 45 percent of the total energy input of natural gas and oil to the facility. To demonstrate compliance with the topping-cycle operating and/or efficiency standards, or to demonstrate that your facility is exempt from the efficiency standard based on the date that installation commenced, respond to lines 13a through 13l below.				
	If you indicated in line 10a that your facility represents bot technology, then respond to lines 13a through 13l below a attributable to the topping-cycle portion of your facility. You which mass and energy flow values and system componence cogeneration system.	considering only the energy Your mass and heat balance on the are for which portion (top	inputs and outputs liagram must make clear		
	13a Indicate the annual average rate of useful thermal en	ergy output made available	Btu/h		
r L	to the host(s), net of any heat contained in condensate ret 13b Indicate the annual average rate of net electrical ene	rgy output	kW		
ılatic	13c Multiply line 13b by 3,412 to convert from kW to Btu/		g Btu/h	Č	
Efficiency Value Calculation	13d Indicate the annual average rate of mechanical energof the shaft of a prime mover for purposes not directly relations value is usually zero)	ated to power production	hp		
alue	13e Multiply line 13d by 2,544 to convert from hp to Btu,		0 Btu/h		
> >:	13f Indicate the annual average rate of energy input from	n natural gas and oil	Btu/h		
ienc	13g Topping-cycle operating value = 100 * 13a / (13a + 1	3c + 13e)	0 %	New Year	
Effic	13h Topping-cycle efficiency value = 100 * (0.5*13a + 13	c + 13e) / 13f	0 %	¥	
	13i Compliance with operating standard: is the operating	g value shown in line 13g gre	ater than or equal to 5%?		
	Yes (complies with operating standard)	[] No (does not comply w			
	13j Did installation of the facility in its current form comm				
	Yes. Your facility is subject to the efficiency requirements of 18 C.F.R. § 292.205(a)(2). Demonstrate compliance with the efficiency requirement by responding to line 13k or 13l, as applicable, below.				
	No. Your facility is exempt from the efficiency standard. Skip lines 13k and 13l.				
	13k Compliance with efficiency standard (for low operation 15%, then indicate below whether the efficiency value)	ing value): If the operating v ue shown in line 13h greater	alue shown in line 13g is less than or equal to 45%:		
	Yes (complies with efficiency standard)	No (does not comply w			
	13I Compliance with efficiency standard (for high operat greater than or equal to 15%, then indicate below wheth equal to 42.5%:	er the efficiency value snown	III IIIIe 1511 15 greater trian or		
	Fill Vos (compiles with efficiency standard)	No (does not comply w	ith efficiency standard)		

Information Required for Bottoming-Cycle Cogeneration Facility If you indicated in line 10a that your facility represents bottoming-cycle cogeneration technology, then you must respond

If you in to the it	dical ems	ted in line 10a that your facility rep on pages 16 and 17. Otherwise, s	presents bottoming-cycle cogeneration technology kip pages 16 and 17.	, men you must respond			
	The thermal energy output of a bottoming-cycle cogeneration facility is the energy related to the process(es) from which at least some of the reject heat is then used for power production. Pursuant to sections 292.202(c) and (e) of the Commission's regulations (18 C.F.R. § 292.202(c) and (e)), the thermal energy output of a qualifying bottoming-cycle cogeneration facility must be useful. In connection with this requirement, describe the process(es) from which at least some of the reject heat is used for power production by responding to lines 14a and 14b below.						
	14a	identify and describe each them host. For hosts with multiple bo separate rows. Name of entity (thermal host) performing the process from which at least some of the reject heat is used for power production	nal host and each bottoming-cycle cogeneration prottoming-cycle cogeneration processes, provide the Thermal host's relationship to facility; Thermal host's process type	ocess engaged in by each data for each process in Has the energy input to the thermal host been augmented for purposes of increasing power production capacity? (if Yes, describe on p. 19)			
	1)		Select thermal host's relationship to facility	Yes No No			
	<u>''</u> _		Select thermal host's process type				
<u> </u>	2)		Select thermal host's relationship to facility	Yes No No			
Yc	-,		Select thermal host's process type				
, h	3)		Select thermal host's relationship to facility	Yes No No			
in Et			Select thermal host's process type				
on		Check here and continue in the	ne Miscellaneous section starting on page 19 if addi	tional space is needed			
Usefulness of Bottoming-Cycle Thermal Output	faci mu add pre faci to t	ntified above. In some cases, this lity's process is not common, and, st provide additional details as ne litional information may be requir viously received a Commission ce lilty, then you need only provide a	thermal output: At a minimum, provide a brief description is sufficient to demonstrate usefuling for if the usefulness of such thermal output is not recessary to demonstrate usefulness. Your application red if an insufficient showing of usefulness is made, entification approving a specific bottoming-cycle probable description of that process and a reference by ith the indicated process. Such exemption may not ade.) If additional space is needed, continue in the	ness. However, it your easonably clear, then you n may be rejected and/or (Exception: if you have ecess related to the Instant date and docket number be used if any material			
Adaptiv				,			

No (does not comply with efficiency standard)

Applicants for facilities representing bottoming-cycle technology and for which installation in the latest process of the Commission's regulations (18 C.F.R. § 292.205(b)) establishes the efficiency standar cogeneration facilities: the useful power output of the facility must be no less than 45 of natural gas and oil for supplementary firing. To demonstrate compilance with the b standard (if applicable), or to demonstrate that your facility is exempt from this standard installation of the facility began, respond to lines 15a through 15h below.	ndards. Section 292.205(b) d for bottoming-cycle percent of the energy input ottoming-cycle efficiency
If you indicated in line 10a that your facility represents both topping-cycle and bottomitechnology, then respond to lines 15a through 15h below considering only the energy attributable to the bottoming-cycle portion of your facility. Your mass and heat balance which mass and energy flow values and system components are for which portion of the (topping or bottoming).	inputs and outputs e diagram must make clear
15a Did installation of the facility in its current form commence on or after March 13, 1 Yes. Your facility is subject to the efficiency requirement of 18 C.F.R. § 292.2056 with the efficiency requirement by responding to lines 15b through 15h below	980? b), Demonstrate compiland
No. Your facility is exempt from the efficiency standard. Skip the rest of page	
15b Indicate the annual average rate of net electrical energy output	kW
	1777
15c Multiply line 15b by 3,412 to convert from kW to Btu/h	0 Btu/
15c Multiply line 15b by 3,412 to convert from kW to Btu/h 15d Indicate the annual average rate of mechanical energy output taken directly off of the shaft of a prime mover for purposes not directly related to power production (this value is usually zero)	
15d Indicate the annual average rate of mechanical energy output taken directly off of the shaft of a prime mover for purposes not directly related to power production (this value is usually zero)	0 Btu/
15d Indicate the annual average rate of mechanical energy output taken directly off of the shaft of a prime mover for purposes not directly related to power production	g Btu/ hp

Yes (complies with efficiency standard)

Certificate of Completeness, Accuracy and Authority

Applicant must certify compliance with and understanding of filing requirements by checking next to each item below and signing at the bottom of this section. Forms with incomplete Certificates of Completeness, Accuracy and Authority will be

ejected by the secretary of the commission		
	ring: (check all items and applicable subitems)	
mass and heat balance diagrams, and knows its contents.	g any Information contained in any attached docu any Information contained in the Miscellaneous s	ection starting on page 19, and
	lred information for certification, and the provided and belief.	
He or she possess full power and auth Practice and Procedure (18 C.F.R. § 38	ority to sign the filing; as required by Rule 2005(a) 5.2005(a)(3)), he or she is one of the following: (ch	(3) of the Commission's Rules of eck one)
 The person on whose behalf t 	he filing is made	
	trust, association, or other organized group on bel	
An officer, agent, or employed filing is made	of the governmental authority, agency, or instrum	entality on behalf of which the
A representative qualified to practice and Procedure (18 C.)	oractice before the Commission under Rule 2101 o F.R. § 385.2101) and who possesses authority to sig	f the Commission's Rules of yn
He or she has reviewed all automatic Miscellaneous section starting on pag	calculations and agrees with their results, unless o ge 19.	therwise noted in the
interconnect and transact (see lines 4 facility and those utilities reside. See page 3 for more information.	Form 556 and all attachments to the utilities with a through 4d), as well as to the regulatory authorit the Required Notice to Public Utilities and State Re	ies of the states in which the egulatory Authorities section on
Procedure (18 C.F.R. § 385,2005(c)) provide	ture date below. Rule 2005(c) of the Commission's es that persons filing their documents electronical led documents. A person filing this document ele- ded below.	ly may use typed characters
Your Signature	Your address	Date
, cor angularit	808 Travis Street #700	
Leslie A. Freiman	Houston, TX 77002	1/26/2017
Audit Notes		
Commission Staff Use Only:		🗆

Page 19 - All Facilities

FERC Form 556

Miscellaneous

Use this space to provide any information for which there was not sufficient space in the previous sections of the form to provide. For each such item of information *clearly identify the line number that the information belongs to.* You may also use this space to provide any additional information you believe is relevant to the certification of your facility.

Your response below is not limited to one page. Additional page(s) will automatically be inserted into this form if the length of your response exceeds the space on this page. Use as many pages as you require.

STANDARD RENEWABLE OFF-SYSTEM VARIABLE POWER PURCHASE

AGREEMENT

THIS AGREEMENT is between <u>Blue Marmot IX LLC</u> ("Seller") and Portland General Electric Company ("PGE") (hereinafter each a "Party" or collectively, "Parties") and is effective upon execution by both Parties ("Effective Date").

RECITALS

Seller intends to construct, own, operate and maintain a <u>Solar</u> facility for the generation of electric power located in <u>Lake (W-120.382, N 42.260)</u> County, <u>Oregon</u> with a Nameplate Capacity Rating of <u>10,000</u> kilowatt ("kW"), as further described in Exhibit A ("Facility"); and

Seller intends to operate the Facility as a "Qualifying Facility," as such term is defined in Section 3.1.3, below.

Seller shall sell and PGE shall purchase the entire Net Output, as such term is defined in Section 1.21, below, from the Facility in accordance with the terms and conditions of this Agreement.

AGREEMENT

NOW, THEREFORE, the Parties mutually agree as follows:

SECTION 1: DEFINITIONS

When used in this Agreement, the following terms shall have the following meanings:

- 1.1. "As-built Supplement" means the supplement to Exhibit A provided by Seller in accordance with Section 4.3 following completion of construction of the Facility, describing the Facility as actually built.
- 1.2. "Base Hours" is defined as the total number of hours in each Contract Year (8,760 or 8,784 for leap year)
- 1.3. "Billing Period" means from the start of the first day of each calendar month to the end of the last day of each calendar month.
- 1.4. "Cash Escrow" means an agreement by two parties to place money into the custody of a third party for delivery to a grantee only after the fulfillment of the conditions specified.
- 1.5. "Commercial Operation Date" means the date that the Facility is deemed by PGE to be fully operational and reliable. PGE may, at its discretion require, among other things, that all of the following events have occurred:
- 1.5.1. (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from a Licensed

Professional Engineer ("LPE") acceptable to PGE in its reasonable judgment stating that the Facility is able to generate electric power reliably in accordance with the terms and conditions of this Agreement (certifications required under this Section 1.5 can be provided by one or more LPEs);

- 1.5.2. Start-Up Testing of the Facility has been completed in accordance with Section 1.36;
- 1.5.3. (facilities with nameplate under 500 kW exempt from following requirement) After PGE has received notice of completion of Start-Up Testing, PGE has received a certificate addressed to PGE from an LPE stating that the Facility has operated for testing purposes under this Agreement and was continuously mechanically available for operation for a minimum of 120 hours. The Facility must provide ten (10) working days written notice to PGE prior to the start of the initial testing period. If the mechanical availability of the Facility is interrupted during this initial testing period or any subsequent testing period, the Facility shall promptly start a new Test Period and provide PGE forty-eight (48) hours written notice prior to the start of such testing period;
- 1.5.4. (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from an LPE stating that all required interconnection facilities have been constructed and all required interconnection tests have been completed;
- 1.5.5. (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from an LPE stating that Seller has obtained all Required Facility Documents and, if requested by PGE in writing, has provided copies of any or all such requested Required Facility Documents;
- 1.5.6. PGE has received a copy of the executed Generation Interconnection and Transmission Agreements.
- 1.6. "Contract Price" means the applicable price, including on-peak and offpeak prices, as specified in the Schedule.
- 1.7. "Contract Year" means each twelve (12) month period commencing upon the Commercial Operation Date or its anniversary during the Term, except the final Contract Year will be the period from the last anniversary of the Commercial Operation Date during the Term until the end of the Term.
 - 1.8. "Effective Date" has the meaning set forth in Section 2.1.
- 1.9. "Environmental Attributes" shall mean any and all claims, credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical or other substance to the air, soil or water. Environmental Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil or water such as (subject to the foregoing) sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; and (2) any avoided emissions of carbon dioxide (CO2), methane (CH4), and other greenhouse gasses (GHGs) that have been determined by the United Nations

Intergovernmental Panel on Climate Change to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere.

- 1.10. "Facility" has the meaning set forth in the Recitals.
- 1.11. "Generation Interconnection Agreement" means an agreement governing the interconnection of the Facility with <u>Pacificorp</u> electric system.
- 1.12. "Generation Unit" means each separate electrical generator that contributes toward Nameplate Capacity Rating included in Exhibit A. For solar facilities, a generating unit is a complete solar electrical generation system within the Facility that is able to generate and deliver energy to the Point of Delivery independent of other Generation Units within the same Facility.
- 1.13. "Letter of Credit" means an engagement by a bank or other person made at the request of a customer that the issuer will honor drafts or other demands for payment upon compliance with the conditions specified in the letter of credit.
- 1.14. "Licensed Professional Engineer" or "LPE" means a person who is licensed to practice engineering in the state where the Facility is located, who has no economic relationship, association, or nexus with the Seller, and who is not a representative of a consulting engineer, contractor, designer or other individual involved in the development of the Facility, or of a manufacturer or supplier of any equipment installed in the Facility. Such Licensed Professional Engineer shall be licensed in an appropriate engineering discipline for the required certification being made and be acceptable to PGE in its reasonable judgment.
- 1.15. "Lost Energy" means "Lost Energy" means ((the Guarantee of Mechanical Availability as set forth in 3.1.10 / MAP) X Net Output for a Calendar Year) Net Output for the Calendar Year. Lost Energy shall be zero unless the result of the calculation in this subsection results in a positive number.
- 1.16. "Lost Energy Value" means Lost Energy X the excess of the annual time-weighted average Mid-C Index Price for On Peak Hours and Off Peak Hours over the time weighted average Contract Price for On Peak and Off Peak Hours for the corresponding time period (provided that such excess shall not exceed the Contract Price and further provided that Lost Energy is deemed to be zero prior to reaching the Commercial Operation Date) plus any reasonable costs incurred by PGE to purchase replacement power and/or transmission to deliver the replacement power to the Point of Delivery (For Start-Up Lost Energy Value See 1.35).
- 1.17. "Mechanical Availability Percentage" or "MAP" shall mean that percentage for any Contract Year for the Facility calculated in accordance with the following formula:

MAP = 100 X (Operational Hours) /(Base Hours X Number of Units)

1.18. "Mid-C Index Price" means the Day Ahead Intercontinental Exchange ("ICE") index price for the bilateral OTC market for energy at the Mid-C Physical for Average On Peak Power and Average Off Peak Power found on the following website:

https://www.theice.com/products/OTC/Physical-Energy/Electricity. In the event ICE no longer publishes this index, PGE and the Seller agree to select an alternative successor index representative of the Mid-C trading hub.

- 1.19. "Nameplate Capacity Rating" means the maximum capacity of the Facility as stated by the manufacturer, expressed in kW, which shall not exceed 10,000 kW.
- 1.20. "Net Dependable Capacity" means the maximum capacity the Facility can sustain over a specified period modified for seasonal limitations, if any, and reduced by the capacity required for station service or auxiliaries.
- 1.21. "Net Output" means all energy expressed in kWhs produced by the Facility, less station and other onsite use and less transformation and transmission losses.
- 1.22. "Number of Units" means the number of Generation Units in the Facility as specified in Exhibit A.
 - 1.23. "Off-Peak Hours" has the meaning provided in the Schedule.
 - 1.24. "On-Peak Hours" has the meaning provided in the Schedule.
- 1.25. "Operational Hours" for the Facility means the total across all Generation Units of the number of hours each of the Facility's Generation Units are potentially capable of producing power at its Nameplate Capacity Rating regardless of actual weather conditions, season and the time of day or night, without any mechanical operating constraint or restriction, and potentially capable of delivering such power to the Point of Delivery in a Contract Year. During up to, but not more than, two hundred (200) hours of Planned Maintenance during a Contract Year for each Generation Unit and hours during which an event of Force Majeure exists, a Generation Unit shall be considered potentially capable of delivering such power to the Point of Delivery. For example, in the absence of any Planned Maintenance beyond 200 hours on any Generation Unit or Event of Force Majeure, the Operational Hours for a wind farm with five (5) separate two (2) MW turbines would be 43,800 for a Contract Year.
- 1.26. "Planned Maintenance" means outages scheduled ninety (90) days in advance, with PGE's prior written consent, which shall not be unreasonably withheld.
 - 1.27. "Point of Delivery" means the PGE system.
- 1.28. "Pre-Commercial Operation Date Minimum Net Output" shall mean, unless such MWh is specifically set forth by Seller in Exhibit A, an amount in MWh equal to seventy-five percent (75%) of Nameplate Capacity Rating X thirty percent (30%) for a wind or other renewable QF or fifty percent (50%) for a solar QF X (whole months since the date selected in Section 2.2.1 / 12) X (8760 hours 200 hours (assumed Planned Maintenance)) for each month. If Seller has provided specific expected monthly Net Output amounts for the Facility in Exhibit A, "Pre-Commercial Operation Date Minimum Net Output" shall mean seventy-five percent (75%) X expected net output set forth in Exhibit A for each month.

- 1.29. "Prime Rate" means the publicly announced prime rate or reference rate for commercial loans to large businesses with the highest credit rating in the United States in effect from time to time quoted by Citibank, N.A. If a Citibank, N.A. prime rate is not available, the applicable Prime Rate shall be the announced prime rate or reference rate for commercial loans in effect from time to time quoted by a bank with \$10 billion or more in assets in New York City, N.Y., selected by the Party to whom interest based on the prime rate is being paid.
- 1.30. "Prudent Electrical Practices" means those practices, methods, standards and acts engaged in or approved by a significant portion of the electric power industry in the Western Electricity Coordinating Council that at the relevant time period, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with good business practices, reliability, economy, safety and expedition, and which practices, methods, standards and acts reflect due regard for operation and maintenance standards recommended by applicable equipment suppliers and manufacturers, operational limits, and all applicable laws and regulations. Prudent Electrical Practices are not intended to be limited to the optimum practice, method, standard or act to the exclusion of all others, but rather to those practices, methods and acts generally acceptable or approved by a significant portion of the electric power generation industry in the relevant region, during the relevant period, as described in the immediate preceding sentence.
 - 1.31. "Required Facility Documents" means all licenses, permits, authorizations, and agreements necessary for construction, operation, interconnection, and maintenance of the Facility including without limitation those set forth in Exhibit B.
 - 1.32. "RPS Attributes" means all attributes related to the Net Output generated by the Facility that are required in order to provide PGE with "qualifying electricity," as that term is defined in Oregon's Renewable Portfolio Standard Act, Ore. Rev. Stat. 469A.010, in effect at the time of execution of this Agreement. RPS Attributes do not include Environmental Attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity and not needed to ensure that there are zero net emissions associated with the generation of electricity.
 - 1.33. "Schedule" shall mean PGE Schedule 201 filed with the Oregon Public Utilities Commission ("Commission") in effect on the Effective Date of this Agreement and attached hereto as Exhibit D, the terms of which are hereby incorporated by reference.
 - 1.34. "Senior Lien" means a prior lien which has precedence as to the property under the lien over another lien or encumbrance
 - 1.35. "Start-Up Lost Energy Value" means for the period after the date specified in Section 2.2.2 but prior to achievement of the Commercial Operation Date: zero, unless the Net Output is less than the pro-rated Pre-Commercial Operation Date Minimum Net Output for the applicable delay period, and the time-weighted average of the delay period's Mid-C Index Price for On-Peak Hours and Off-Peak Hours is greater

than the time-weighted average of the delay period's Contract Price for On-Peak Hours and Off-Peak Hours, in which case Startup Lost Energy Value equals: (pro-rated Pre-commercial Operation Date Minimum Net Output for the applicable period - Net Output for the applicable period) X (the lower of: the time-weighted average of the Contract Price for On-Peak hours and Off-Peak Hours during the applicable period; or (the time-weighted average of the Mid-C Index Price for On-Peak Hours and Off-Peak Hours during the applicable period — the time-weighted average of the Contract Price for On-Peak Hours and Off-Peak Hours during the applicable period)). The time-weighted average in this section will reflect the relative proportions of On-Peak Hours and Off-Peak Hours in each day.

- 1.36. "Start-Up Testing" means the completion of applicable required factory and start-up tests as set forth in Exhibit C.
- 1.37. "Step-in Rights" means the right of one party to assume an intervening position to satisfy all terms of an agreement in the event the other party fails to perform its obligations under the agreement.
- 1.38. "Term" shall mean the period beginning on the Effective Date and ending on the Termination Date.
- 1.39. "Test Period" shall mean a period of sixty (60) days or a commercially reasonable period determined by the Seller.
- 1.40. "Transmission Agreement" means an agreement executed by the Seller and the Transmission Provider(s) for Transmission Services.
- 1.41. "Transmission Curtailment" means a limitation on Seller's ability to deliver any portion of the scheduled energy to PGE due to the unavailability of transmission to the Point of Delivery (for any reason other than Force Majeure).
- 1.42. "Transmission Curtailment Replacement Energy Cost" means the greater of zero or the amount calculated as: ((Mid-C Index Price Contract Price) X curtailed energy) for periods of Transmission Curtailment.
- 1.43. "Transmission Provider(s)" means the signatory (other than the Seller) to the Transmission Agreement.
- 1.44. "Transmission Services" means any and all services (including but not limited to ancillary services and control area services) required for the firm transmission and delivery of Energy from the Facility to the Point of Delivery for a term not less than the Term of this Agreement.

References to Recitals, Sections, and Exhibits are to be the recitals, sections and exhibits of this Agreement.

SECTION 2: TERM; COMMERCIAL OPERATION DATE

2.1. This Agreement shall become effective upon execution by both Parties ("Effective Date").

- 2.2. Time is of the essence of this Agreement, and Seller's ability to meet certain requirements prior to the Commercial Operation Date and to complete all requirements to establish the Commercial Operation Date is critically important. Therefore,
 - 2.2.1. By March 1, 2020 Seller shall begin initial deliveries of Net Output; and
- 2.2.2. By March 31, 2020 Seller shall have completed all requirements under Section 1.5 and shall have established the Commercial Operation Date.
- 2.2.3. Unless the Parties agree in writing that a later Commercial Operation Date is reasonable and necessary, the Commercial Operation Date shall be no more than three (3) years from the Effective Date. PGE will not unreasonably withhold agreement to a Commercial Operation Date that is more than three (3) years from the Effective date if the Seller has demonstrated that a later Commercial Operation Date is reasonable and necessary.
- 2.3. This Agreement shall terminate on the date 18 years after the effective date, or the date the Agreement is terminated in accordance with Section 8 or 11, whichever is earlier ("Termination Date").

SECTION 3: REPRESENTATIONS AND WARRANTIES

- 3.1. Seller and PGE represent, covenant, and warrant as follows:
- 3.1.1. Seller warrants it is a <u>Limited Liability Company</u> duly organized under the laws of <u>Delaware</u>.
- 3.1.2. Seller warrants that the execution and delivery of this Agreement does not contravene any provision of, or constitute a default under, any indenture, mortgage, or other material agreement binding on Seller or any valid order of any court, or any regulatory agency or other body having authority to which Seller is subject.
- 3.1.3. Seller warrants that the Facility is and shall for the Term of this Agreement continue to be a "Qualifying Facility" ("QF") as that term is defined in the version of 18 C.F.R. Part 292 in effect on the Effective Date. Seller has provided the appropriate QF certification, which may include a Federal Energy Regulatory Commission ("FERC") self-certification to PGE prior to PGE's execution of this Agreement. At any time during the Term of this Agreement, PGE may require Seller to provide PGE with evidence satisfactory to PGE in its reasonable discretion that the Facility continues to qualify as a QF under all applicable requirements.
- 3.1.4. Seller warrants that it has not within the past two (2) years been the debtor in any bankruptcy proceeding, and Seller is and will continue to be for the Term of this Agreement current on all of its financial obligations.
- 3.1.5. Seller warrants that during the Term of this Agreement, all of Seller's right, title and interest in and to the Facility shall be free and clear of all liens and encumbrances other than liens and encumbrances arising from third-party financing of the Facility other than workers', mechanics', suppliers' or similar liens, or tax liens, in each case arising in the ordinary course of business that are either not yet due and

payable or that have been released by means of a performance bond acceptable to PGE posted within eight (8) calendar days of the commencement of any proceeding to foreclose the lien.

- 3.1.6. Seller warrants that it will design and operate the Facility consistent with Prudent Electrical Practices.
- 3.1.7. Seller warrants that the Facility has a Nameplate Capacity Rating not greater than 10,000 kW.
 - 3.1.8. Seller warrants that Net Dependable Capacity of the Facility is 10,000 kW.
- 3.1.9. Seller estimates that the average annual Net Output to be delivered by the Facility to PGE is <u>21,891,000</u> kilowatt-hours ("kWh"), which amount PGE will include in its resource planning.
- 3.1.10. Seller represents and warrants that the Facility shall achieve the following Mechanical Availability Percentages ("Guarantee of Mechanical Availability"):
- 3.1.10.1. Ninety percent (90%) beginning in the first Contract Year and extending through the Term for the Facility, if the Facility was operational and sold electricity to PGE or another buyer prior to the Effective Date of this Agreement; or
- 3.1.10.2. Ninety percent (90%) beginning in Contract Year three and extending throughout the remainder of the Term.
- 3.1.10.3. Annually, within 90 days of the end of each Contract Year, Seller shall send to PGE a detailed written report demonstrating and providing evidence of the actual MAP for the previous Contract Year.
- 3.1.10.4. Seller's failure to meet the Guarantee of Mechanical Availability in a Calendar Year shall result in damages payable to PGE by Seller equal to the Lost Energy Value. PGE shall bill Seller for such damages in accordance with Section 7.
- 3.1.11. Seller will deliver from the Facility to PGE at the Point of Delivery Net Output not to exceed a maximum of 33,750,000 kWh of Net Output during each Contract Year ("Maximum Net Output"). The cost of delivering energy from the Facility to PGE is the sole responsibility of the Seller.
- 3.1.12. By the Commercial Operation Date, Seller has entered into a Generation Interconnection Agreement for a term not less than the term of this Agreement.
- 3.1.13. PGE warrants that it has not within the past two (2) years been the debtor in any bankruptcy proceeding, and PGE is and will continue to be for the Term of this Agreement current on all of its financial obligations.
- 3.1.14. Seller warrants that the Facility satisfies the eligibility requirements specified in the Definition of a Small Cogeneration Facility or Small Power Production Facility Eligible to Receive the Standard Renewable Rates and Standard Renewable PPA in PGE's Schedule and Seller will not make any changes in its ownership, control or management during the term of this Agreement that would cause it to not be in compliance with the Definition of a Small Cogeneration Facility or Small Power

Production Facility Eligible to Receive the Standard Renewable Rates and Standard Renewable PPA in PGE's Schedule. Seller will provide, upon request by PGE not more frequently than every 36 months, such documentation and information as may be reasonably required to establish Seller's continued compliance with such Definition. PGE agrees to take reasonable steps to maintain the confidentiality of any portion of the above described documentation and information that the Seller identifies as confidential except PGE will provide all such confidential information to the Commission upon the Commission's request.

3.1.15. Seller warrants that it will comply with all requirements necessary for all Transferred RECs (as defined in Section 4.5) associated with Net Output to be issued, monitored, accounted for, and transferred by and through the Western Renewable Energy Generation System consistent with the provisions of OAR 330-160-0005 through OAR 330-160-0050. PGE warrants that it will reasonably cooperate in Seller's efforts to meet such requirements, including, for example serving as the qualified reporting entity for the Facility if the Facility is located in PGE's balancing authority.

SECTION 4: DELIVERY OF POWER, PRICE AND ENVIRONMENTAL ATTRIBUTES

- 4.1. Commencing on the Effective Date and continuing through the Term of this Agreement, Seller shall sell to PGE the entire Net Output delivered from the Facility at the Point of Delivery.
 - 4.2. PGE shall pay Seller the Contract Price for all delivered Net Output.
- 4.3. Upon completion of construction of the Facility, Seller shall provide PGE an As-built Supplement to specify the actual Facility as built. Seller shall not increase the Nameplate Capacity Rating above that specified in Exhibit A or increase the ability of the Facility to deliver Net Output in quantities in excess of the Net Dependable of the Facility to deliver Net Output as described in Section 3.1.11 above, through Capacity, or the Maximum Net Output as described in Section 3.1.11 above, through any means including, but not limited to, replacement, modification, or addition of existing equipment, except with prior written notice to PGE. In the event Seller increases the Nameplate Capacity Rating of the Facility to no more than 10,000 kW pursuant to this Nameplate Capacity Rating to greater than 10,000 kW, then event Seller increases the Nameplate Capacity Rating to greater than 10,000 kW, then event Seller increases the Nameplate Capacity Rating to greater than 10,000 kW, then Seller shall be required to enter into a new power purchase agreement for all delivered Net Output proportionally related to the increase of Nameplate Capacity above 10,000 kW.
 - 4.4. Seller shall provide preschedules for all deliveries of energy hereunder, including identification of receiving and generating control areas, by 9:00:00 PPT on the last business day prior to the scheduled date of delivery. All energy shall be scheduled according to the most current North America Energy Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) scheduling rules and practices. The Parties' respective representatives shall maintain hourly real-time schedule coordination; provided, however, that in the absence of such coordination, the hourly schedule established by the exchange of preschedules shall be considered final. Seller and PGE shall maintain records of hourly energy schedules for accounting and

operating purposes. The final E-Tag shall be the controlling evidence of the Parties' schedule. All energy shall be prescheduled according to customary WECC scheduling practices. Seller shall make commercially reasonable efforts to schedule in any hour an amount equal to its expected Net Output for such hour. Seller shall maintain a minimum of two years records of Net Output and shall agree to allow PGE to have access to such records and to imbalance information kept by the Transmission Provider.

From the start of the Renewable Resource Deficiency Period through the remainder of the Term of this Agreement, Seller shall provide and PGE shall acquire the RPS Attributes for the Contract Years as specified in the Schedule and Seller shall retain ownership of all other Environmental Attributes (if any). During the Renewable Resource Sufficiency Period, Seller shall retain all Environmental Attributes in accordance with the Schedule. The Contract Price includes full payment for the Net Output and any RPS Attributes transferred to PGE under this Agreement. With respect to Environmental Attributes not transferred to PGE under this Agreement ("Seller-Retained Environmental Attributes") Seller may report under §1605(b) of the Energy Policy Act of 1992 or under any applicable program as belonging to Seller any of the Seller-Retained Environmental Attributes, and PGE shall not report under such program that such Seller-Retained Environmental Attributes belong to it. With respect to RPS Attributes transferred to PGE under this Agreement ("Transferred RECs"), PGE may report under §1605(b) of the Energy Policy Act of 1992 or under any applicable program as belonging to it any of the Transferred RECs, and Seller shall not report under such program that such Transferred RECs belong to it.

SECTION 5: OPERATION AND CONTROL

- 5.1. Seller shall operate and maintain the Facility in a safe manner in accordance with the Generation Interconnection Agreement, and Prudent Electrical Practices. PGE shall have no obligation to purchase Net Output from the Facility to the extent the interconnection of the Facility to PGE's electric system is disconnected, suspended or interrupted, in whole or in part, pursuant to the Generation Interconnection Agreement, or to the extent generation curtailment is required as a result of Seller's noncompliance with the Generation Interconnection Agreement. Seller is solely responsible for the operation and maintenance of the Facility. PGE shall not, by reason of its decision to inspect or not to inspect the Facility, or by any action or inaction taken with respect to any such inspection, assume or be held responsible for any liability or occurrence arising from the operation and maintenance by Seller of the Facility.
- 5.2. Seller agrees to provide sixty (60) days advance written notice of any scheduled maintenance that would require shut down of the Facility for any period of time.
- 5.3. If the Facility ceases operation for unscheduled maintenance, Seller immediately shall notify PGE of the necessity of such unscheduled maintenance, the time when such maintenance has occurred or will occur, and the anticipated duration of such maintenance. Seller shall take all reasonable measures and exercise its best

efforts to avoid unscheduled maintenance, to limit the duration of such unscheduled maintenance, and to perform unscheduled maintenance during Off-Peak hours.

SECTION 6: CREDITWORTHINESS

In the event Seller: a) is unable to represent or warrant as required by Section 3 that it has not been a debtor in any bankruptcy proceeding within the past two (2) years; b) becomes such a debtor during the Term; or c) is not or will not be current on all its financial obligations, Seller shall immediately notify PGE and shall promptly (and in no less than 10 days after notifying PGE) provide default security in an amount reasonably acceptable to PGE in one of the following forms: Senior Lien, Step-in Rights, a Cash Escrow or Letter of Credit. The amount of such default security that shall be acceptable to PGE shall be equal to: (annual On Peak Hours) X (On Peak Price – Off Peak Price) X (Net Dependable Capacity). Notwithstanding the foregoing, in the event Seller is not current on construction related financial obligations, Seller shall notify PGE of such delinquency and PGE may, in its discretion, grant an exception to the requirements to provide default security if the QF has negotiated financial arrangements with the construction loan lender that mitigate Seller's financial risk to PGE.

SECTION 7: BILLINGS, COMPUTATIONS AND PAYMENTS

- 7.1. On or before the thirtieth (30th) day following the end of each Billing Period, PGE shall send to Seller payment for Seller's deliveries of Net Output to PGE, together with computations supporting such payment. PGE may offset any such payment to reflect amounts owing from Seller to PGE pursuant to this Agreement and any other agreement related to the Facility between the Parties or otherwise. On or before the thirtieth (30th) day following the end of each Contract Year, PGE shall bill for any Lost Energy Value accrued pursuant to this Agreement.
- 7.2. Any amounts owing after the due date thereof shall bear interest at the Prime Rate plus two percent (2%) from the date due until paid; provided, however, that the interest rate shall at no time exceed the maximum rate allowed by applicable law.

SECTION 8: DEFAULT, REMEDIES AND TERMINATION

- 8.1. In addition to any other event that may constitute a default under this Agreement, the following events shall constitute defaults under this Agreement:
- 8.1.1. Breach by Seller or PGE of a representation or warranty, except for Section 3.1.4, set forth in this Agreement.
- 8.1.2. Seller's failure to provide default security, if required by Section 6, prior to delivery of any Net Output to PGE or within 10 days of notice.
- 8.1.3. Seller's failure to meet the Guarantee of Mechanical Availability established in Section 3.1.10 for two consecutive Contract Years or Seller's failure to provide any written report required by that section.
 - 8.1.4. If Seller is no longer a Qualifying Facility.
 - 8.1.5. Failure of PGE to make any required payment pursuant to Section 7.1.

- 8.1.6. Seller's failure to meet the Commercial Operation Date.
- 8.2. In the event of a default under Section 8.1.6, PGE may provide Seller with written notice of default. Seller shall have one year in which to cure the default during which time the Seller shall pay PGE damages equal to the Lost Energy Value. If Seller is unable to cure the default, PGE may immediately terminate this Agreement as provided in Section 8.3. PGE's resource sufficiency/deficiency position shall have no bearing on PGE's right to terminate the Agreement under this Section 8.2.
- 8.3. In the event of a default hereunder, except as otherwise provided in this Agreement, the non-defaulting party may immediately terminate this Agreement at its sole discretion by delivering written notice to the other Party. In addition, the non-defaulting Party may pursue any and all legal or equitable remedies provided by law or pursuant to this Agreement including damages related to the need to procure replacement power. A termination hereunder shall be effective upon the date of delivery of notice, as provided in Section 20. The rights provided in this Section 8 are cumulative such that the exercise of one or more rights shall not constitute a waiver of any other rights.
- 8.4. If this Agreement is terminated as provided in this Section 8, PGE shall make all payments, within thirty (30) days, that, pursuant to the terms of this Agreement, are owed to Seller as of the time of receipt of notice of default. PGE shall not be required to pay Seller for any Net Output delivered by Seller after such notice of default.
- 8.5. In the event PGE terminates this Agreement pursuant to this Section 8, and Seller wishes to again sell Net Output to PGE following such termination, PGE in its sole discretion may require that Seller shall do so subject to the terms of this Agreement, including but not limited to the Contract Price until the Term of this Agreement (as set forth in Section 2.3) would have run in due course had the Agreement remained in effect. At such time Seller and PGE agree to execute a written document ratifying the terms of this Agreement.
- 8.6. Sections 8.1, 8.4, 8.5, 10, and 19.2 shall survive termination of this Agreement.

SECTION 9: TRANSMISSION CURTAILMENTS

- 9.1. Seller shall give PGE notice as soon as reasonably practicable of any Transmission Curtailment that is likely to affect Seller's ability to deliver any portion of energy scheduled pursuant to Section 4.4 of this Agreement.
- 9.2. If as the result of a Transmission Curtailment, Seller does not deliver any portion of energy (including real-time adjustments), scheduled pursuant to Section 4.4 of this Agreement, Seller shall pay PGE the Transmission Curtailment Replacement Energy Cost for the number of MWh of energy reasonably determined by PGE as the difference between (i) the scheduled energy that would have been delivered to PGE under this Agreement during the period of Transmission Curtailment and (ii) the actual energy, if any, that was delivered to PGE for the period.

SECTION 10: INDEMNIFICATION AND LIABILITY

- 10.1. Seller agrees to defend, indemnify and hold harmless PGE, its directors, officers, agents, and representatives against and from any and all loss, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with Seller's delivery of electric power to PGE or with the facilities at or prior to the Point of Delivery, or otherwise arising out of this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PGE, Seller or others, excepting to the extent such loss, claim, action or suit may be caused by the negligence of PGE, its directors, officers, employees, agents or representatives.
- 10.2. PGE agrees to defend, indemnify and hold harmless Seller, its directors, officers, agents, and representatives against and from any and all loss, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with PGE's receipt of electric power from Seller or with the facilities at or after the Point of Delivery, or otherwise arising out of this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PGE, Seller or others, excepting to the extent such loss, claim, action or suit may be caused by the negligence of Seller, its directors, officers, employees, agents or representatives.
- 10.3. Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a Party to this Agreement. No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or to the public, nor affect the status of PGE as an independent public utility corporation or Seller as an independent individual or entity.
- 10.4. NEITHER PARTY SHALL BE LIABLE TO THE OTHER FOR SPECIAL, PUNITIVE, INDIRECT OR CONSEQUENTIAL DAMAGES, WHETHER ARISING FROM CONTRACT, TORT (INCLUDING NEGLIGENCE), STRICT LIABILITY OR OTHERWISE.

SECTION 11: INSURANCE

11.1. Prior to the connection of the Facility to PGE's electric system, provided such Facility has a design capacity of 200 kW or more, Seller shall secure and continuously carry for the Term hereof, with an insurance company or companies rated not lower than "B+" by the A. M. Best Company, insurance policies for bodily injury and property damage liability. Such insurance shall include provisions or endorsements naming PGE, it directors, officers and employees as additional insureds; provisions that such insurance is primary insurance with respect to the interest of PGE and that any insurance or self-insurance maintained by PGE is excess and not contributory insurance with the insurance required hereunder; a cross-liability or severability of

insurance interest clause; and provisions that such policies shall not be canceled or their limits of liability reduced without thirty (30) days' prior written notice to PGE. Initial limits of liability for all requirements under this section shall be \$1,000,000 million single limit, which limits may be required to be increased or decreased by PGE as PGE limit, which limits reasonable judgment economic conditions or claims experience may warrant.

- 11.2. Prior to the connection of the Facility to PGE's electric system, provided such facility has a design capacity of 200 kW or more, Seller shall secure and continuously carry for the Term hereof, in an insurance company or companies rated not lower than "B+" by the A. M. Best Company, insurance acceptable to PGE against property damage or destruction in an amount not less than the cost of replacement of the Facility. Seller promptly shall notify PGE of any loss or damage to the Facility. Unless the Parties agree otherwise, Seller shall repair or replace the damaged or destroyed Facility, or if the facility is destroyed or substantially destroyed, it may terminate this Agreement. Such termination shall be effective upon receipt by PGE of written notice from Seller. Seller shall waive its insurers' rights of subrogation against PGE regarding Facility property losses.
- 11.3. Prior to the connection of the Facility to PGE's electric system and at all other times such insurance policies are renewed or changed, Seller shall provide PGE with a copy of each insurance policy required under this Section, certified as a true copy by an authorized representative of the issuing insurance company or, at the discretion of PGE, in lieu thereof, a certificate in a form satisfactory to PGE certifying the issuance of such insurance. If Seller fails to provide PGE with copies of such currently effective insurance policies or certificates of insurance, PGE at its sole discretion and without limitation of other remedies, may upon ten (10) days advance written notice by certified or registered mail to Seller either withhold payments due Seller until PGE has received such documents, or purchase the satisfactory insurance and offset the cost of obtaining such insurance from subsequent power purchase payments under this Agreement.

SECTION 12: FORCE MAJEURE

12.1. As used in this Agreement, "Force Majeure" or "an event of Force Majeure" means any cause beyond the reasonable control of the Seller or of PGE which, despite the exercise of due diligence, such Party is unable to prevent or overcome. By way of example, Force Majeure may include but is not limited to acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes, and other labor disturbances, earthquakes, fires, lightning, epidemics, sabotage, restraint by court order or other delay or failure in the performance as a result of any action or inaction on behalf of a public authority which by the exercise of reasonable foresight such Party could not reasonably have been expected to avoid and by the exercise of due diligence, it shall be unable to overcome, subject, in each case, to the requirements of the first sentence of this paragraph. Force Majeure, however, specifically excludes the cost or availability of resources to operate the Facility, changes in market conditions that affect

the price of energy or transmission, wind or water droughts, and obligations for the payment of money when due.

- 12.2. If either Party is rendered wholly or in part unable to perform its obligation under this Agreement because of an event of Force Majeure, that Party shall be excused from whatever performance is affected by the event of Force Majeure to the extent and for the duration of the Force Majeure, after which such Party shall recommence performance of such obligation, provided that:
- 12.2.1. the non-performing Party, shall, promptly, but in any case within one (1) week after the occurrence of the Force Majeure, give the other Party written notice describing the particulars of the occurrence; and
- 12.2.2. the suspension of performance shall be of no greater scope and of no longer duration than is required by the Force Majeure; and
- 12.2.3. the non-performing Party uses its best efforts to remedy its inability to perform its obligations under this Agreement.
- 12.3. No obligations of either Party which arose before the Force Majeure causing the suspension of performance shall be excused as a result of the Force Majeure.
- 12.4. Neither Party shall be required to settle any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to the Party's best interests.

SECTION 13: SEVERAL OBLIGATIONS

Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership or joint venture or to impose a trust or partnership duty, obligation or liability between the Parties. If Seller includes two or more parties, each such party shall be jointly and severally liable for Seller's obligations under this Agreement.

SECTION 14: CHOICE OF LAW

This Agreement shall be interpreted and enforced in accordance with the laws of the state of Oregon, excluding any choice of law rules which may direct the application of the laws of another jurisdiction.

SECTION 15: PARTIAL INVALIDITY AND PURPA REPEAL

It is not the intention of the Parties to violate any laws governing the subject matter of this Agreement. If any of the terms of the Agreement are finally held or determined to be invalid, illegal or void as being contrary to any applicable law or public policy, all other terms of the Agreement shall remain in effect. If any terms are finally held or determined to be invalid, illegal or void, the Parties shall enter into negotiations held or determined to be invalid, illegal or void, the purpose of achieving conformity concerning the terms affected by such decision for the purpose of achieving conformity with requirements of any applicable law and the intent of the Parties to this Agreement.

In the event the Public Utility Regulatory Policies Act (PURPA) is repealed, this Agreement shall not terminate prior to the Termination Date, unless such termination is mandated by state or federal law.

SECTION 16: WAIVER

Any waiver at any time by either Party of its rights with respect to a default under this Agreement or with respect to any other matters arising in connection with this Agreement must be in writing, and such waiver shall not be deemed a waiver with respect to any subsequent default or other matter.

SECTION 17: GOVERNMENTAL JURISDICTION AND AUTHORIZATIONS

This Agreement is subject to the jurisdiction of those governmental agencies having control over either Party or this Agreement. Seller shall at all times maintain in effect all local, state and federal licenses, permits and other approvals as then may be required by law for the construction, operation and maintenance of the Facility, and shall provide upon request copies of the same to PGE.

SECTION 18: SUCCESSORS AND ASSIGNS

This Agreement and all of the terms hereof shall be binding upon and inure to the benefit of the respective successors and assigns of the Parties. No assignment hereof by either Party shall become effective without the written consent of the other Party being first obtained and such consent shall not be unreasonably withheld. Notwithstanding the foregoing, either Party may assign this Agreement without the other Party's consent as part of (a) a sale of all or substantially all of the assigning Party's assets, or (b) a merger, consolidation or other reorganization of the assigning Party.

SECTION 19: ENTIRE AGREEMENT

- 19.1. This Agreement supersedes all prior agreements, proposals, representations, negotiations, discussions or letters, whether oral or in writing, regarding PGE's purchase of Net Output from the Facility. No modification of this Agreement shall be effective unless it is in writing and signed by both Parties.
- 19.2. By executing this Agreement, Seller releases PGE from any third party claims related to the Facility, known or unknown, which may have arisen prior to the Effective Date.

SECTION 20: NOTICES

20.1. All notices except as otherwise provided in this Agreement shall be in writing, shall be directed as follows and shall be considered delivered if delivered in person or when deposited in the U.S. Mail, postage prepaid by certified or registered mail and return receipt requested:

c/o EDP Renewables North America LLC;

Blue Marmot IX LLC

808 Travis Suite 808_ Houston, TX 77002

Attention: General Counsel;

To Seller:

with a copy to:					
To PGE:	Contracts Manager QF Contracts, 3WT PGE - 121 SW Sal Portland, Oregon	rC0306 mon St. 97204		•	÷
or their addresses, by pro	TDEOE the Parties	hereto have	e caused this A		
PGE By: Name: Title: Date:			Approved E Business Terms Crecia Legal Rich Mal	Control of the State of the Sta	
Blue Marmot IX LLC (Name Seller) By: Name: Steve Irvin Title: Executive Vice Pr Date: (3, 29)					

Brian Hayes

A-1

EXHIBIT A DESCRIPTION OF SELLER'S FACILITY

The facility will be a solar PV plant consisting of 38,715 polycrystalline modules of nominal 335W rating each. Total plant rating will be 12.970 MWdc/10MWac. Modules will be mounted to single-axis trackers.

Central inverter stations will be located at intermediate points in the PV field.

Modules will be evenly distributed to the inverter stations. The total inverter nameplate rating will be 10.0MWac. Each inverter will be directly coupled to a 34.5kV step-up transformer. The transformers will be connected to a 34.5kV AC collection system, which will feed into the plant switchgear.

The plant switchgear will feed a 34.5kV transmission line, which will run overhead approximately 4.8 miles to the PacifiCorp Mile-Hi Substation.

Inside the Mile-Hi Substation, the transmission line will connect to a new bay containing a facility-owned 34.5kV/115kV GSU transformer, associated breakers, switching, bus, and controls.

The facility-owned components at Mile-Hi substation are considered part of the self-certified qualifying facility.

Solar Facility Characteristics:	e of project construction and is subject to design finalization
1 Congration	
a PVSvst (or equivalent) simulation results detail, including	g but not limited to: 23866
i. Annual MWh (AC) for the first calendar year of commerc	0.007
ii Annual degradation factor	C t-b "Concration"
iii. Average 24-hr profile of generation MWh (AC) for each	m. See tab Generation 0.272442922
iv. Expected Solar Capacity Factor	See tab "Generation"
v. Maximum annual output (monthly MWh detail)	See tab "Generation"
iv. Loss Diagram	266 FAD GELICIATION
2. Description of Modules:	Polycrystalline Silicon
a. Module type	38715
b. # of modules	37.4V
c. Max power voltage	8.97A
d. Max power current	1500V
e. Max system voltage	12970kW
f. Total DC system size	12370111
3. Description of Racking	and the second control of the second control
a Racking	Single-Axis Tracking
i. Type: (fixed tilt, single-axis tracking, or dual-axis tracki	ng. Single Axis Hasking
ii. Tilt angle (if fixed-tilt)	South-Facing
iii. Azimuth (default = south-facing)	Joden (deling
4. Description of Inverters:	
a. Number of Inverters	ABB PVS980-58-1818kVA-
b. Model	2910kW D0
c. Maximum Power (kW)	60
d. Operating Voltage (VAC)	1925
e. Max. Output Current (A)	150
f. Rated DC Voltage	194
g. Rated DC current	200
h. Maximum Output (kW)	10.0M\
g. Facility AC Capacity Rating	1,29
h. Inverter loading ratio	10.0M\
i. Facility AC rating	

The state of the s	particle of the second of the
5. Description of transformers	The second secon
Inverter LV-MV	5
a. # of transformers	ABB PadPlus+
	34500
b. Model	600
c. High Voltage Rating	and the second s
d. Low Voltage Rating	2.0 each, 10.0 total
e. MVA rating	Wye-Ground
f. High voltage connection	Wye.
h connection	
GSU MV-HV	1
	ABB 10MVA
a. # of transformers	115000
b. Model	34500
c. High Voltage Rating	the state of the s
d. Low Voltage Rating	10/12.5 ONAF
e MVA rating	Wye
s usebuoltage connection	Delta
g. Low voltage connection	Otor and back to PV plant SCADA
g. Low voltage connections, communications, and monit	orin, and transmit data to Operator and back to PV plant SCADA hase at Mile Hi substation for Customer controls equipment
6. Description of metering, communication	orin, and transmit data to Operator under controls equipment hase at Mile Hi substation for Customer controls equipment asmismission agreements prior to commercial operation date.
7. Description of station service requirements	remismission agreements prior to commercial operation date.
8 Description and timeline of interconnection and train	hase at Mille in substation of the hase at Mille in substation of the hase as Mille in substation of the hase as Mille in substation of the hase at Mille in
O Transaction Service Request Number, Interconnection	nsmission agreements prior to commercial operation date on Q'ansmission agreements prior to commercial operation date
9. Hansactori service and the	

FEDERAL ENERGY REGULATORY COMMISSION WASHINGTON, DC

OMB Control # 1902-0075 Expiration 06/30/2019

Form 556 Certification of Qualifying Facility (QF) Status for a Small Power Production or Cogeneration Facility

General

Ouestions about completing this form should be sent to Form556@ferc.gov. Information about the Commission's QF program, answers to frequently asked questions about QF requirements or completing this form, and contact information for QF program staff are available at the Commission's QF website, <u>www.ferc.gov/QF</u>. The Commission's QF website also provides links to the Commission's QF regulations (18 C.F.R. § 131.80 and Part 292), as well as other statutes and orders pertaining to the Commission's QF program.

Who Must File

Any applicant seeking QF status or recertification of QF status for a generating facility with a net power production capacity (as determined in lines 7a through 7g below) greater than 1000 kW must file a self-certification or an application for Commission certification of QF status, which includes a properly completed Form 556. Any applicant seeking QF status for a generating facility with a net power production capacity 1000 kW or less is exempt from the certification requirement, and is therefore not required to complete or file a Form 556. See 18 C.F.R. § 292.203.

How to Complete the Form 556

This form is intended to be completed by responding to the items in the order they are presented, according to the instructions given. If you need to back-track, you may need to clear certain responses before you will be allowed to change other responses made previously in the form. If you experience problems, click on the nearest help button () for assistance, or contact Commission staff at Form556@ferc.gov.

Certain lines in this form will be automatically calculated based on responses to previous lines, with the relevant formulas shown. You must respond to all of the previous lines within a section before the results of an automatically calculated field will be displayed. If you disagree with the results of any automatic calculation on this form, contact Commission staff at Form556@ferc.gov to discuss the discrepancy before filing.

You must complete all lines in this form unless instructed otherwise. Do not alter this form or save this form in a different format. Incomplete or altered forms, or forms saved in formats other than PDF, will be rejected.

How to File a Completed Form 556

Applicants are required to file their Form 556 electronically through the Commission's eFiling website (see instructions on page 2). By filing electronically, you will reduce your filing burden, save paper resources, save postage or courier charges, help keep Commission expenses to a minimum, and receive a much faster confirmation (via an email containing the docket number assigned to your facility) that the Commission has received your filing.

If you are simultaneously filing both a waiver request and a Form 556 as part of an application for Commission certification, see the "Waiver Requests" section on page 3 for more information on how to file.

Paperwork Reduction Act Notice

This form is approved by the Office of Management and Budget. Compliance with the information requirements established by the FERC Form No. 556 is required to obtain or maintain status as a QF. See 18 C.F.R. § 131.80 and Part 292. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The estimated burden for completing the FERC Form No. 556, including gathering and reporting information, is as follows: 3 hours for self-certification of a small power production facility, 8 hours for self-certifications of a cogeneration facility, 6 hours for an application for Commission certification of a small power production facility, and 50 hours for an application for Commission certification of a cogeneration facility. Send comments regarding this burden estimate or any aspect of this collection of information, including suggestions for reducing this burden, to the following: Information Clearance Officer, Office of the Executive Director (ED-32), Federal Energy Regulatory Commission, 888 First Street N.E., Washington, DC 20426 (DataClearance@ferc.gov); and Desk Officer for FERC, Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (oira submission@omb.eop.gov). Include the Control No. 1902-0075 in any correspondence.

Electronic Filing (eFiling)

To electronically file your Form 556, visit the Commission's QF website at www.ferc.gov/QF and click the eFiling link.

If you are eFiling your first document, you will need to register with your name, email address, mailing address, and phone number. If you are registering on behalf of an employer, then you will also need to provide the employer name, alternate contact name, alternate contact phone number and and alternate contact email.

Once you are registered, log in to eFiling with your registered email address and the password that you created at registration. Follow the instructions. When prompted, select one of the following QF-related filing types, as appropriate, from the Electric or General filing category.

Filing category	Filing Type as listed in eFiling	Description
	(Fee) Application for Commission Cert. as Cogeneration QF	Use to submit an application for Commission certification or Commission recertification of a cogeneration facility as a QF.
	(Fee) Application for Commission Cert. as Small Power QF	Use to submit an application for Commission certification or Commission recertification of a small power production facility as a QF.
	Self-Certification Notice (QF, EG, FC)	Use to submit a notice of self- certification of your facility (cogeneration or small power production) as a QF.
Electric	Self-Recertification of Qualifying Facility (QF)	Use to submit a notice of self- recertification of your facility (cogeneration or small power production) as a QF.
	Supplemental Information or Request	Use to correct or supplement a Form 556 that was submitted with errors or omissions, or for which Commission staff has requested additional information. Do not use this filing type to report new changes to a facility or its ownership; rather, use a self- recertification or Commission recertification to report such changes.
General	(Fee) Petition for Declaratory Order (not under FPA Part 1)	Use to submit a petition for declaratory order granting a waiver of Commission QF regulations pursuant to 18 C.F.R. §§ 292.204(a) (3) and/or 292.205(c). A Form 556 is not required for a petition for declaratory order unless Commission recertification is being requested as part of the petition.

You will be prompted to submit your filing fee, if applicable, during the electronic submission process. Filing fees can be paid via electronic bank account debit or credit card.

During the eFiling process, you will be prompted to select your file(s) for upload from your computer.

FERC Form 556 Page 3 - Instructions

Filing Fee

No filing fee is required if you are submitting a self-certification or self-recertification of your facility as a QF pursuant to 18 C.F.R. § 292.207(a).

A filing fee is required if you are filing either of the following:

- (1) an application for Commission certification or recertification of your facility as a QF pursuant to 18 C.F.R. § 292.207(b), or
- (2) a petition for declaratory order granting waiver pursuant to 18 C.F.R. §§ 292.204(a)(3) and/or 292.205(c).

The current fees for applications for Commission certifications and petitions for declaratory order can be found by visiting the Commission's QF website at www.ferc.gov/QF and clicking the Fee Schedule link.

You will be prompted to submit your filing fee, if applicable, during the electronic filing process described on page 2.

Required Notice to Utilities and State Regulatory Authorities

Pursuant to 18 C.F.R. § 292.207(a)(ii), you must provide a copy of your self-certification or request for Commission certification to the utilities with which the facility will interconnect and/or transact, as well as to the State regulatory authorities of the states in which your facility and those utilities reside. Links to information about the regulatory authorities in various states can be found by visiting the Commission's QF website at www.ferc.gov/QF and clicking the Notice Requirements link.

What to Expect From the Commission After You File

An applicant filing a Form 556 electronically will receive an email message acknowledging receipt of the filing and showing the docket number assigned to the filing. Such email is typically sent within one business day, but may be delayed pending confirmation by the Secretary of the Commission of the contents of the filing.

An applicant submitting a self-certification of QF status should expect to receive no documents from the Commission, other than the electronic acknowledgement of receipt described above. Consistent with its name, a self-certification is a certification by the applicant itself that the facility meets the relevant requirements for QF status, and does not involve a determination by the Commission as to the status of the facility. An acknowledgement of receipt of a self-certification, in particular, does not represent a determination by the Commission with regard to the QF status of the facility. An applicant self-certifying may, however, receive a rejection, revocation or deficiency letter if its application is found, during periodic compliance reviews, not to comply with the relevant requirements.

An applicant submitting a request for Commission certification will receive an order either granting or denying certification of QF status, or a letter requesting additional information or rejecting the application. Pursuant to 18 C.F.R. § 292.207(b)(3), the Commission must act on an application for Commission certification within 90 days of the later of the filing date of the application or the filing date of a supplement, amendment or other change to the application.

Waiver Requests

18 C.F.R. § 292.204(a)(3) allows an applicant to request a waiver to modify the method of calculation pursuant to 18 C.F.R. § 292.204(a)(2) to determine if two facilities are considered to be located at the same site, for good cause. 18 C.F.R. § 292.205(c) allows an applicant to request waiver of the requirements of 18 C.F.R. §§ 292.205(a) and (b) for operating and efficiency upon a showing that the facility will produce significant energy savings. A request for waiver of these requirements must be submitted as a petition for declaratory order, with the appropriate filing fee for a petition for declaratory order. Applicants requesting Commission recertification as part of a request for waiver of one of these requirements should electronically submit their completed Form 556 along with their petition for declaratory order, rather than filing their Form 556 as a separate request for Commission recertification. Only the filing fee for the petition for declaratory order must be paid to cover both the waiver request and the request for recertification if such requests are made simultaneously.

18 C.F.R. § 292.203(d)(2) allows an applicant to request a waiver of the Form 556 filing requirements, for good cause. Applicants filing a petition for declaratory order requesting a waiver under 18 C.F.R. § 292.203(d)(2) do not need to complete or submit a Form 556 with their petition.

Geographic Coordinates

If a street address does not exist for your facility, then line 3c of the Form 556 requires you to report your facility's geographic coordinates (latitude and longitude). Geographic coordinates may be obtained from several different sources. You can find links to online services that show latitude and longitude coordinates on online maps by visiting the Commission's QF webpage at www.ferc.gov/QF and clicking the Geographic Coordinates link. You may also be able to obtain your geographic coordinates from a GPS device, Google Earth (available free at https://earth.google.com), a property survey, various engineering or construction drawings, a property deed, or a municipal or county map showing property lines.

Filing Privileged Data or Critical Energy Infrastructure Information in a Form 556

The Commission's regulations provide procedures for applicants to either (1) request that any information submitted with a Form 556 be given privileged treatment because the information is exempt from the mandatory public disclosure requirements of the Freedom of Information Act, 5 U.S.C. § 552, and should be withheld from public disclosure; or (2) identify any documents containing critical energy infrastructure information (CEII) as defined in 18 C.F.R. § 388.113 that should not be made public.

If you are seeking privileged treatment or CEII status for any data in your Form 556, then you must follow the procedures in 18 C.F.R. § 388.112. See www.ferc.gov/help/filing-guide/file-ceii.asp for more information.

Among other things (see 18 C.F.R. § 388.112 for other requirements), applicants seeking privileged treatment or CEII status for data submitted in a Form 556 must prepare and file both (1) a complete version of the Form 556 (containing the privileged and/or CEII data), and (2) a public version of the Form 556 (with the privileged and/or CEII data redacted). Applicants preparing and filing these different versions of their Form 556 must indicate below the security designation of this version of their document. If you are *not* seeking privileged treatment or CEII status for any of your Form 556 data, then you should not respond to any of the items on this page.

Non-Public: Applicant is seeking privileged treatment and/or CEII status for data contained in the Form 556 lines indicated below. This non-public version of the applicant's Form 556 contains all data, including the data that is redacted in the (separate) public version of the applicant's Form 556.
Public (redacted): Applicant is seeking privileged treatment and/or CEII status for data contained in the Form 556 lines indicated below. This public version of the applicants's Form 556 contains all data except for data from the lines indicated below, which has been redacted.
Privileged : Indicate below which lines of your form contain data for which you are seeking privileged treatment
Critical Energy Infrastructure Information (CEII): Indicate below which lines of your form contain data for which you are seeking CEII status

The eFiling process described on page 2 will allow you to identify which versions of the electronic documents you submit are public, privileged and/or CEII. The filenames for such documents should begin with "Public", "Priv", or "CEII", as applicable, to clearly indicate the security designation of the file. Both versions of the Form 556 should be unaltered PDF copies of the Form 556, as available for download from www.ferc.gov/QF. To redact data from the public copy of the submittal, simply omit the relevant data from the Form. For numerical fields, leave the redacted fields blank. For text fields, complete as much of the field as possible, and replace the redacted portions of the field with the word "REDACTED" in brackets. Be sure to identify above all fields which contain data for which you are seeking non-public status.

The Commission is not responsible for detecting or correcting filer errors, including those errors related to security designation. If your documents contain sensitive information, make sure they are filed using the proper security designation.

FEDERAL ENERGY REGULATORY COMMISSION WASHINGTON, DC

OMB Control # 1902-0075 Expiration 06/30/2019

Form 556 Certification of Qualifying Facility (QF) Status for a Small Power Production or Cogeneration Facility

1b Applicant street at 808 Travis Str			
1c City		1d State/provi	ince
Houston		TX	
1e Postal code 77002	1f Country (if not United States)		1g Telephone number 713–265–0350
1h Has the instant fac	ility ever previously been certified as a Q	F? Yes N	No 🔀
1i If yes, provide the o	locket number of the last known QF filing	g pertaining to tl	nis facility: QF
1j Under which certif	cation process is the applicant making th	nis filing?	
Notice of self-ce (see note below)	rtification \Box_{fe}^{A}	pplication for Co ee; see "Filing Fee	ommission certification (requires filing e" section on page 3)
QF status. A notic notice of self-cert	f-certification is a notice by the applicant te of self-certification does not establish a ification to verify compliance. See the "W for more information.	a proceeding, an	d the Commission does not review a
1k What type(s) of QF	status is the applicant seeking for its fac	ility? (check all th	nat apply)
Qualifying small	power production facility status 🔲 C	ualifying cogen	eration facility status
1	e and expected effective date(s) of this fi	_	
	tion; facility expected to be installed by		nd to begin operation on 3/31/20
	reviously certified facility to be effective of change(s) below, and describe chang		language section starting on mage 10)
	-	e(s) in the Miscei	ianeous section starting on page 19)
Name chang	e and/or other administrative change(s)		
l territoria	•	production capa	acity and/or cogeneration thermal output
	orrection to a previous filing submitted o		,
	oplement or correction in the Miscellane	***************************************	ng on page 19)
	wing three statements is true, check the l ible, explaining any special circumstance		ribe your situation and complete the form neous section starting on page 19.
previously gra	ility complies with the Commission's QF nted by the Commission in an order date Niscellaneous section starting on page 19	ed	virtue of a waiver of certain regulations (specify any other relevant waiver
	ility would comply with the Commission vith this application is granted	's QF requiremer	nts if a petition for waiver submitted
employment of	cility complies with the Commission's reg of unique or innovative technologies not orion of compliance via this form difficult	contemplated b	special circumstances, such as the y the structure of this form, that make escribe in Misc. section starting on p. 19)

	2a Name of contact person Leslie A. Freiman			2b Telephone number 713–265–0350	
	2c Which of the following describes:	the contact person's relation	nship to the ap	plicant? (check one)	
	2c Which of the following describes the contact person's relationship to the applicant? (check one) Applicant (self)				
'n	Employee of a company affiliated with the applicant authorized to represent the applicant on this matter				
Contact Information	Lawyer, consultant, or other representative authorized to represent the applicant on this matter				
Ш	2d Company or organization name				
for	EDP Renewables North Ameri		, CHECK HEIE AND	a skip to line ze)	
<u>l</u>			: 2-1 \ Z		
act	2e Street address (if same as Application	ant, check here and skip to	ine 3a) 🔀		الآيا
nte					
ပိ					-
	2f City		2g State/provi	ince	
	2h Postal code	2i Country (if not United S	States)		
_	3a Facility name				
ior	Blue Marmot IX				
cat	3b Street address (if a street address	s does not exist for the facil	ity, check here a	ınd skìp to line 3c)⊠	
ŏ					
٦					
Facility Identification and Location	then you must specify the latitude the following formula to convert degrees + (minutes/60) + (secon	de and longitude coordinat to decimal degrees from d ds/3600). See the "Geogra	es of the facility legrees, minutes aphic Coordinat	our facility by checking the box in line 3b, in degrees (to three decimal places). Use s and seconds: decimal degrees = es" section on page 4 for help. If you ographic coordinates below is optional.	
lentii	Longitude East (+) 120	0.382 degrees	Latitude	North (+) 42.260 degrees	
)	3d City (if unincorporated, check he	ere and enter nearest city)	3e State/p	rovince	
<u>∃</u>	Lakeview		OR		
aci	3f County (or check here for indepe	endent city) 3g	Country (if not	t United States)	
ഥ	Lake				
	Identify the electric utilities that are o	contemplated to transact w	ith the facility.		
es	4a Identify utility interconnecting w	vith the facility]
<u> </u>	PacifiCorp (Pacific Powe	er)			
) Hi	4b Identify utilities providing wheel	ling service or check here if	none		lG
l g	PacifiCorp (Pacific Powe	•	dy y Created for P		
_tir	4c Identify utilities purchasing the u	useful electric power outpu	t or check here i	fnone	
sac	Portland General Electri			kanssund	
Transacting Utilities		ementary power, backup p	ower, maintena	nce power, and/or interruptible power	
'	PacifiCorp (Pacific Power	**			

	Direct ownership as of effective date or operation date: Identify all direct owners of t percent equity interest. For each identified owner, also (1) indicate whether that own defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or a holding com 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(8)), and (2 utilities or holding companies, provide the percentage of equity interest in the facility direct owners hold at least 10 percent equity interest in the facility, then provide the two direct owners with the largest equity interest in the facility.	ner is an electric npany, as define 2) for owners wh y held by that o	utility, as ed in section nich a re ele ctric owner. If no
	Full legal names of direct owners	Electric utilit holding company	% equity
1		Yes 🕅 No	
2		Yes ☐ No	
3		Yes □ No	
4		Yes ☐ No	<u> </u>
5		Yes ☐ No	
6		Yes No	
7		Yes No	
8		Yes No	
9)	Yes 🔲 No	
1	0)	Yes 🔲 No	
5b	Upstream (i.e., indirect) ownership as of effective date or operation date: Identify all of the facility that both (1) hold at least 10 percent equity interest in the facility, and defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or holding comp 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(8)). Also equity interest in the facility held by such owners. (Note that, because upstream owners)	(2) are electric u panies, as define provide the per	itilities, as ed in section centage of
5b	of the facility that both (1) hold at least 10 percent equity interest in the facility, and defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or holding comp 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(8)). Also equity interest in the facility held by such owners. (Note that, because upstream own another, total percent equity interest reported may exceed 100 percent.) Check here if no such upstream owners exist.	(2) are electric u panies, as define provide the per ners may be suk	ntilities, as ed in section centage of osidiaries of one % equity
	of the facility that both (1) hold at least 10 percent equity interest in the facility, and defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or holding comp 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(8)). Also equity interest in the facility held by such owners. (Note that, because upstream own another, total percent equity interest reported may exceed 100 percent.) Check here if no such upstream owners exist. Full legal names of electric utility or holding company upstream own	(2) are electric u panies, as define provide the per ners may be suk	ntilities, as ed in section centage of osidiaries of one % equity interest
1	of the facility that both (1) hold at least 10 percent equity interest in the facility, and defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or holding comp 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(8)). Also equity interest in the facility held by such owners. (Note that, because upstream own another, total percent equity interest reported may exceed 100 percent.) Check here if no such upstream owners exist. Full legal names of electric utility or holding company upstream own EDP Renewables North America LLC	(2) are electric u panies, as define provide the per ners may be suk	ntilities, as ed in section centage of osidiaries of one % equity
	of the facility that both (1) hold at least 10 percent equity interest in the facility, and defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or holding comp 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(8)). Also equity interest in the facility held by such owners. (Note that, because upstream own another, total percent equity interest reported may exceed 100 percent.) Check here if no such upstream owners exist. Full legal names of electric utility or holding company upstream own EDP Renewables North America LLC	(2) are electric u panies, as define provide the per ners may be suk	ntilities, as ed in section centage of osidiaries of one % equity interest
1 2	of the facility that both (1) hold at least 10 percent equity interest in the facility, and defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or holding comp 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(8)). Also equity interest in the facility held by such owners. (Note that, because upstream own another, total percent equity interest reported may exceed 100 percent.) Check here if no such upstream owners exist. Full legal names of electric utility or holding company upstream own EDP Renewables North America LLC)	(2) are electric u panies, as define provide the per ners may be suk	ntilities, as ed in section centage of osidiaries of one % equity interest
1 2 3	of the facility that both (1) hold at least 10 percent equity interest in the facility, and defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or holding comp 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(8)). Also equity interest in the facility held by such owners. (Note that, because upstream own another, total percent equity interest reported may exceed 100 percent.) Check here if no such upstream owners exist. Full legal names of electric utility or holding company upstream own EDP Renewables North America LLC))	(2) are electric u panies, as define provide the per ners may be suk	ntilities, as ed in section centage of osidiaries of one % equity interest
1 2 3 4	of the facility that both (1) hold at least 10 percent equity interest in the facility, and defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or holding comp 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(8)). Also equity interest in the facility held by such owners. (Note that, because upstream own another, total percent equity interest reported may exceed 100 percent.) Check here if no such upstream owners exist. Full legal names of electric utility or holding company upstream own EDP Renewables North America LLC)) ()) ()) () () () () ((2) are electric u panies, as define provide the per ners may be suk	ntilities, as ed in section centage of osidiaries of one % equity interest
1 2 3 4 5	of the facility that both (1) hold at least 10 percent equity interest in the facility, and defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or holding comp 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(8)). Also equity interest in the facility held by such owners. (Note that, because upstream own another, total percent equity interest reported may exceed 100 percent.) Check here if no such upstream owners exist. Full legal names of electric utility or holding company upstream own EDP Renewables North America LLC)))))	(2) are electric u panies, as define provide the per ners may be suk	ntilities, as ed in section centage of osidiaries of one % equity interest
1 2 3 4 5	of the facility that both (1) hold at least 10 percent equity interest in the facility, and defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or holding comp 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(8)). Also equity interest in the facility held by such owners. (Note that, because upstream own another, total percent equity interest reported may exceed 100 percent.) Check here if no such upstream owners exist. Full legal names of electric utility or holding company upstream own EDP Renewables North America LLC)) ()))))))))	(2) are electric u panies, as define provide the per ners may be suk	ntilities, as ed in section centage of osidiaries of one % equity interest
1 2 3 4 5 6	of the facility that both (1) hold at least 10 percent equity interest in the facility, and defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or holding comp 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(8)). Also equity interest in the facility held by such owners. (Note that, because upstream own another, total percent equity interest reported may exceed 100 percent.) Check here if no such upstream owners exist. Full legal names of electric utility or holding company upstream own EDP Renewables North America LLC)))))))))))))	(2) are electric u panies, as define provide the per ners may be suk	ntilities, as ed in section centage of osidiaries of one % equity interest
1 2 3 4 5 6 7 8	of the facility that both (1) hold at least 10 percent equity interest in the facility, and defined in section 3(22) of the Federal Power Act (16 U.S.C. 796(22)), or holding comp 1262(8) of the Public Utility Holding Company Act of 2005 (42 U.S.C. 16451(8)). Also equity interest in the facility held by such owners. (Note that, because upstream own another, total percent equity interest reported may exceed 100 percent.) Check here if no such upstream owners exist. Full legal names of electric utility or holding company upstream own EDP Renewables North America LLC)))))))))))))	(2) are electric u panies, as define provide the per ners may be suk	ntilities, as ed in section centage of osidiaries of one % equity interest

Describe the primary energy input: (check one main category and, if applicable, one subcategory) Biomass (specify) Renewable resources (specify) Geothermal Landfill gas Hydro power - river Fossil fuel (specify) Manure digester gas Hydro power - tidal Coal (not waste) Municipal solid waste Hydro power - wave Fuel oil/diesel Sewage digester gas Solar - photovoltaic Natural gas (not waste) Wood Solar - thermal Other fossil fuel (describe on page 19) Wind (describe on page 19) Waste (specify type below in line 6b) Other renewable resource (describe on page 19) Waste fuel listed in 18 C.F.R. § 292.202(b) (specify one of the following) Anthracite refuse that has an average heat content of 6,000 Btu or less per pound and has an average ash content of 45 percent or more Bituminous coal refuse that has an average heat content of 9,500 Btu per pound or less and has an average ash content of 25 percent or more Top or bottom subbituminous coal produced on Federal lands or on Indian lands that has been determined to be waste by the United States Department of the Interior's Bureau of Land Managemen (BLM) or that is located on non-Federal or non-Indian lands outside of BLM's jurisdiction, provided that the applicant shows that the latter coal is an extension of that determined by BLM to be waste Coal refuse produced on Federal lands or on Indian lands outside of BLM's jurisdiction, provided that applicant shows that the latter is an extension of that determined by BLM to be waste Lignite produced in association with the production of montan wax and lignite that becomes exposed as a result of such a mining operation Gaseous fuels (except natural gas and synthetic gas from coal) (describe on page 19) Waste natural gas from gas or oil wells (describe on page 19 how the gas meets the requirements of 1 C.F.R. § 2.400 for waste natural gas; include with your filling any materials necessary to demonstrate
Landfill gas
Manure digester gas
Municipal solid waste Hydro power - wave Fuel oil/diesel
Sewage digester gas Solar - photovoltaic Natural gas (not was Wood Solar - thermal Other fossil fuel (describe on page 19 Wind Other biomass (describe on page 19 Wind Other fossil fuel (describe on page 19 Waste (specify type below in line 6b) Other renewable resource Other (describe on page 19 Other (desc
Wood Solar - thermal Other fossil fuel (describe on page 19) Wind Other biomass (describe on page 19) Wind Other biomass (describe on page 19) Wind Other fossil fuel (describe on page 19) Other renewable resource Other (describe on page 19)
Other biomass (describe on page 19)
Waste (specify type below in line 6b)
Waste fuel listed in 18 C.F.R. § 292.202(b) (specify one of the following) Waste fuel listed in 18 C.F.R. § 292.202(b) (specify one of the following) Anthracite culm produced prior to July 23, 1985 Anthracite refuse that has an average heat content of 6,000 Btu or less per pound and has an average ash content of 45 percent or more Bituminous coal refuse that has an average heat content of 9,500 Btu per pound or less and has an average ash content of 25 percent or more Top or bottom subbituminous coal produced on Federal lands or on Indian lands that has been determined to be waste by the United States Department of the Interior's Bureau of Land Managemen (BLM) or that is located on non-Federal or non-Indian lands outside of BLM's jurisdiction, provided that the applicant shows that the latter coal is an extension of that determined by BLM to be waste Coal refuse produced on Federal lands or on Indian lands outside of BLM's jurisdiction, provided that applicant shows that the latter is an extension of that determined by BLM to be waste Lignite produced in association with the production of montan wax and lignite that becomes exposed as a result of such a mining operation Gaseous fuels (except natural gas and synthetic gas from coal) (describe on page 19) Waste natural gas from gas or oil wells (describe on page 19 how the gas meets the requirements of 1 C.F.R. § 2.400 for waste natural gas; include with your filing any materials necessary to demonstrate
Anthracite culm produced prior to July 23, 1985 Anthracite refuse that has an average heat content of 6,000 Btu or less per pound and has an average ash content of 45 percent or more Bituminous coal refuse that has an average heat content of 9,500 Btu per pound or less and has an average ash content of 25 percent or more Top or bottom subbituminous coal produced on Federal lands or on Indian lands that has been determined to be waste by the United States Department of the Interior's Bureau of Land Managemen (BLM) or that is located on non-Federal or non-Indian lands outside of BLM's jurisdiction, provided that the applicant shows that the latter coal is an extension of that determined by BLM to be waste Coal refuse produced on Federal lands or on Indian lands that has been determined to be waste by the BLM or that is located on non-Federal or non-Indian lands outside of BLM's jurisdiction, provided that applicant shows that the latter is an extension of that determined by BLM to be waste Lignite produced in association with the production of montan wax and lignite that becomes exposed as a result of such a mining operation Gaseous fuels (except natural gas and synthetic gas from coal) (describe on page 19) Waste natural gas from gas or oil wells (describe on page 19 how the gas meets the requirements of 1 C.F.R. § 2.400 for waste natural gas; include with your filing any materials necessary to demonstrate
Anthracite refuse that has an average heat content of 6,000 Btu or less per pound and has an average ash content of 45 percent or more Bituminous coal refuse that has an average heat content of 9,500 Btu per pound or less and has an average ash content of 25 percent or more Top or bottom subbituminous coal produced on Federal lands or on Indian lands that has been determined to be waste by the United States Department of the Interior's Bureau of Land Management (BLM) or that is located on non-Federal or non-Indian lands outside of BLM's jurisdiction, provided that the applicant shows that the latter coal is an extension of that determined by BLM to be waste Coal refuse produced on Federal lands or on Indian lands that has been determined to be waste by the BLM or that is located on non-Federal or non-Indian lands outside of BLM's jurisdiction, provided that applicant shows that the latter is an extension of that determined by BLM to be waste Lignite produced in association with the production of montan wax and lignite that becomes exposed as a result of such a mining operation Gaseous fuels (except natural gas and synthetic gas from coal) (describe on page 19) Waste natural gas from gas or oil wells (describe on page 19 how the gas meets the requirements of 1 C.F.R. § 2.400 for waste natural gas; include with your filing any materials necessary to demonstrate
ash content of 45 percent or more Bituminous coal refuse that has an average heat content of 9,500 Btu per pound or less and has an average ash content of 25 percent or more Top or bottom subbituminous coal produced on Federal lands or on Indian lands that has been determined to be waste by the United States Department of the Interior's Bureau of Land Managemen (BLM) or that is located on non-Federal or non-Indian lands outside of BLM's jurisdiction, provided that the applicant shows that the latter coal is an extension of that determined by BLM to be waste Coal refuse produced on Federal lands or on Indian lands that has been determined to be waste by the BLM or that is located on non-Federal or non-Indian lands outside of BLM's jurisdiction, provided that applicant shows that the latter is an extension of that determined by BLM to be waste Lignite produced in association with the production of montan wax and lignite that becomes exposed as a result of such a mining operation Gaseous fuels (except natural gas and synthetic gas from coal) (describe on page 19) Waste natural gas from gas or oil wells (describe on page 19 how the gas meets the requirements of 1 C.F.R. § 2.400 for waste natural gas; include with your filling any materials necessary to demonstrate
Bituminous coal refuse that has an average heat content of 9,500 Btu per pound or less and has an average ash content of 25 percent or more Top or bottom subbituminous coal produced on Federal lands or on Indian lands that has been determined to be waste by the United States Department of the Interior's Bureau of Land Management (BLM) or that is located on non-Federal or non-Indian lands outside of BLM's jurisdiction, provided that the applicant shows that the latter coal is an extension of that determined by BLM to be waste Coal refuse produced on Federal lands or on Indian lands outside of BLM's jurisdiction, provided that applicant shows that the latter is an extension of that determined by BLM to be waste Lignite produced in association with the production of montan wax and lignite that becomes exposed as a result of such a mining operation Gaseous fuels (except natural gas and synthetic gas from coal) (describe on page 19) Waste natural gas from gas or oil wells (describe on page 19 how the gas meets the requirements of 1 C.F.R. § 2.400 for waste natural gas; include with your filing any materials necessary to demonstrate
determined to be waste by the United States Department of the Interior's Bureau of Land Management (BLM) or that is located on non-Federal or non-Indian lands outside of BLM's jurisdiction, provided that the applicant shows that the latter coal is an extension of that determined by BLM to be waste Coal refuse produced on Federal lands or on Indian lands that has been determined to be waste by the BLM or that is located on non-Federal or non-Indian lands outside of BLM's jurisdiction, provided that applicant shows that the latter is an extension of that determined by BLM to be waste Lignite produced in association with the production of montan wax and lignite that becomes exposed as a result of such a mining operation Gaseous fuels (except natural gas and synthetic gas from coal) (describe on page 19) Waste natural gas from gas or oil wells (describe on page 19 how the gas meets the requirements of 1 C.F.R. § 2.400 for waste natural gas; include with your filing any materials necessary to demonstrate
as a result of such a mining operation Gaseous fuels (except natural gas and synthetic gas from coal) (describe on page 19) Waste natural gas from gas or oil wells (describe on page 19 how the gas meets the requirements of 1 C.F.R. § 2.400 for waste natural gas; include with your filing any materials necessary to demonstrate
as a result of such a mining operation Gaseous fuels (except natural gas and synthetic gas from coal) (describe on page 19) Waste natural gas from gas or oil wells (describe on page 19 how the gas meets the requirements of 1 C.F.R. § 2.400 for waste natural gas; include with your filing any materials necessary to demonstrate
Waste natural gas from gas or oil wells (describe on page 19 how the gas meets the requirements of 1 ☐ C.F.R. § 2.400 for waste natural gas; include with your filing any materials necessary to demonstrate
☐ C.F.R. § 2.400 for waste natural gas; include with your filing any materials necessary to demonstrate
compliance with 18 C.F.R. § 2.400)
☐ Materials that a government agency has certified for disposal by combustion (describe on page 19)
☐ Heat from exothermic reactions (describe on page 19) ☐ Residual heat (describe on page 1
☐ Used rubber tires ☐ Plastic materials ☐ Refinery off-gas ☐ Petroleum cok
Other waste energy input that has little or no commercial value and exists in the absence of the qualifying facility industry (describe in the Miscellaneous section starting on page 19; include a discussion of the fuel's lack of commercial value and existence in the absence of the qualifying facility industry)
6c Provide the average energy input, calculated on a calendar year basis, in terms of Btu/h for the following fossil fue energy inputs, and provide the related percentage of the total average annual energy input to the facility (18 C.F.
292.202(j)). For any oil or natural gas fuel, use lower heating value (18 C.F.R. § 292.202(m)).
Annual average energy Percentage of total Fuel input for specified fuel annual energy input
Natural gas 0 Btu/h 0 %
Oil-based fuels O Btu/h O %
Coal 0 Btu/h 0 %

Indicate the maximum gross and maximum net electric power production capacity of the facility at the point(s) of delivery by completing the worksheet below. Respond to all items. If any of the parasitic loads and/or losses identified in lines 7b through 7e are negligible, enter zero for those lines.

7a The maximum gross power production capacity at the terminals of the individual generator(s) under the most favorable anticipated design conditions	10,000 kW
7b Parasitic station power used at the facility to run equipment which is necessary and integral to the power production process (boiler feed pumps, fans/blowers, office or maintenance buildings directly related to the operation of the power generating facility, etc.). If this facility includes non-power production processes (for instance, power consumed by a cogeneration facility's thermal host), do not include any power consumed by the non-power production activities in your	
reported parasitic station power.	5 kW
7c Electrical losses in interconnection transformers	102.5 kW
7d Electrical losses in AC/DC conversion equipment, if any	10 kW
7e Other interconnection losses in power lines or facilities (other than transformers and AC/DC conversion equipment) between the terminals of the generator(s) and the point of interconnection with the utility	41 kW
7f Total deductions from gross power production capacity = 7b + 7c + 7d + 7e	158.5 kW
7g Maximum net power production capacity = 7a - 7f	9,841.5 kW

7h Description of facility and primary components: Describe the facility and its operation. Identify all boilers, heat recovery steam generators, prime movers (any mechanical equipment driving an electric generator), electrical generators, photovoltaic solar equipment, fuel cell equipment and/or other primary power generation equipment used in the facility. Descriptions of components should include (as applicable) specifications of the nominal capacities for mechanical output, electrical output, or steam generation of the identified equipment. For each piece of equipment identified, clearly indicate how many pieces of that type of equipment are included in the plant, and which components are normally operating or normally in standby mode. Provide a description of how the components operate as a system. Applicants for cogeneration facilities do not need to describe operations of systems that are clearly depicted on and easily understandable from a cogeneration facility's attached mass and heat balance diagram; however, such applicants should provide any necessary description needed to understand the sequential operation of the facility depicted in their mass and heat balance diagram. If additional space is needed, continue in the Miscellaneous section starting on page 19.

The facility will be a solar PV plant consisting of 38,715 polycrystalline modules of nominal 335W rating each. Total plant rating will be 12.970 MWdc/10MWac. Modules will be mounted to single-axis trackers.

Central inverter stations will be located at intermediate points in the PV field. Modules will be evenly distributed to the inverter stations. The total inverter nameplate rating will be 10.0MWac. Each inverter will be directly coupled to a 34.5kV step-up transformer. The transformers will be connected to a 34.5kV AC collection system, which will feed into the plant switchgear.

The plant switchgear will feed a 34.5kV transmission line, which will run overhead approximately 4.8 miles to the PacifiCorp Mile-Hi Substation.

Inside the Mile-Hi Substation, the transmission line will connect to a new bay containing a facility-owned $34.5 \, kV/115 \, kV$ GSU transformer, associated breakers, switching, bus, and controls.

The facility-owned components at Mile-Hi substation are considered part of the self-certified qualifying facility.



Information Required for Small Power Production Facility

If you indicated in line 1k that you are seeking qualifying small power production facility status for your facility, then you must respond to the items on this page. Otherwise, skip page 10.

IIIusi	respond to the items on this page. Otherwise, sup page 10.	
	Pursuant to 18 C.F.R. § 292.204(a), the power production capacity of any small power production with the power production capacity of any other small power production facilities that use resource, are owned by the same person(s) or its affiliates, and are located at the same site, megawatts. To demonstrate compliance with this size limitation, or to demonstrate that you from this size limitation under the Solar, Wind, Waste, and Geothermal Power Production In (Pub. L. 101-575, 104 Stat. 2834 (1990) as amended by Pub. L. 102-46, 105 Stat. 249 (1991)), rethrough 8e below (as applicable).	the same energy may not exceed 80 our facility is exempt acentives Act of 1990
	8a Identify any facilities with electrical generating equipment located within 1 mile of the equipment of the instant facility, and for which any of the entities identified in lines 5a or 5 at least a 5 percent equity interest.	
Ge	Check here if no such facilities exist. 🔀	
tification of Complian with Size Limitations	Facility location Root docket # (city or county, state) (if any) Common owner(s)	Maximum net power production capacity
m ati	1)QF	kW
nit	2) QF	kW
of I.	3) QF -	kW
tior Size	Check here and continue in the Miscellaneous section starting on page 19 if additiona	I space is needed
Certification of Compliance with Size Limitations	8b The Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990 (Incentives Act of	ertified prior to 1995. e Incentives Act? e)
	8d Did construction of the facility commence on or before December 31, 1999? Yes	No
	8e If you answered No in line 8d, indicate whether reasonable diligence was exercised tove the facility, taking into account all factors relevant to construction? Yes No If you a brief narrative explanation in the Miscellaneous section starting on page 19 of the construction, describe why construction started so long after the facility was certified) and the toward completion of the facility.	u answered Yes, provide uction timeline (in
Certification of Compliance vith Fuel Use Requirements	Pursuant to 18 C.F.R. § 292.204(b), qualifying small power production facilities may use foss amounts, for only the following purposes: ignition; start-up; testing; flame stabilization; co prevention of unanticipated equipment outages; and alleviation or prevention of emergen the public health, safety, or welfare, which would result from electric power outages. The a used for these purposes may not exceed 25 percent of the total energy input of the facility period beginning with the date the facility first produces electric energy or any calendar years.	ntrol use; alleviation or scies, directly affecting amount of fossil fuels during the 12-month
of C Rec	9a Certification of compliance with 18 C.F.R. § 292.204(b) with respect to uses of fossil fuel	:
on c Use	Applicant certifies that the facility will use fossil fuels exclusively for the purposes lis	ted above.
cati Iel I	9b Certification of compliance with 18 C.F.R. § 292.204(b) with respect to amount of fossil	fuel used annually:
Certific vith Fu	Applicant certifies that the amount of fossil fuel used at the facility will not, in agground percent of the total energy input of the facility during the 12-month period beginn facility first produces electric energy or any calendar year thereafter.	

FERC Form 556

Information Required for Cogeneration Facility

If you indicated in line 1k that you are seeking qualifying cogeneration facility status for your facility, then you must respond to the items on pages 11 through 13. Otherwise, skip pages 11 through 13.

	energy (such as heat or suse of energy. Pursuant cycle cogeneration facilithermal application or possible 292.205(a); or (2) for a boapplication or process for application or process for Topping-cycle Topping-cycle to help demonstration or process for the mediance diagram demeet certain requirements	eneration technology does the facility represent? (check all that apply) e cogeneration Bottoming-cycle cogeneration te the sequential operation of the cogeneration process, and to support compliance with s such as the operating and efficiency standards, include with your filing a mass and heat epicting average annual operating conditions. This diagram must include certain items and rements, as described below. You must check next to the description of each requirement
	Check to certify compliance with indicated requirement	nt you have complied with these requirements. Requirement
ation	Indicated requirement	Diagram must show orientation within system piping and/or ducts of all prime movers, heat recovery steam generators, boilers, electric generators, and condensers (as applicable), as well as any other primary equipment relevant to the cogeneration process.
gener ation	yourself the state of the state	Any average annual values required to be reported in lines 10b, 12a, 13a, 13b, 13d, 13f, 14a, 15b, 15d and/or 15f must be computed over the anticipated hours of operation.
General Cogeneration Information		Diagram must specify all fuel inputs by fuel type and average annual rate in Btu/h. Fuel for supplementary firing should be specified separately and clearly labeled. All specifications of fuel inputs should use lower heating values.
ene	promotion of the state of the s	Diagram must specify average gross electric output in kW or MW for each generator.
G		Diagram must specify average mechanical output (that is, any mechanical energy taken off of the shaft of the prime movers for purposes not directly related to electric power generation) in horsepower, if any. Typically, a cogeneration facility has no mechanical output.
		At each point for which working fluid flow conditions are required to be specified (see below), such flow condition data must include mass flow rate (in lb/h or kg/s), temperature (in °F, R, °C or K), absolute pressure (in psia or kPa) and enthalpy (in Btu/lb or kJ/kg). Exception: For systems where the working fluid is <i>liquid only</i> (no vapor at any point in the cycle) and where the type of liquid and specific heat of that liquid are clearly indicated on the diagram or in the Miscellaneous section starting on page 19, only mass flow rate and temperature (not pressure and enthalpy) need be specified. For reference, specific heat at standard conditions for pure liquid water is approximately 1.002 Btu/(lb*R) or 4.195 kJ/(kg*K).
	growing	Diagram must specify working fluid flow conditions at input to and output from each steam turbine or other expansion turbine or back-pressure turbine.
	poweron of the state of the sta	Diagram must specify working fluid flow conditions at delivery to and return from each thermal application.
	grationing	Diagram must specify working fluid flow conditions at make-up water inputs.

	EPAct 2005 cogeneration facilities: The Energy Policy Act of 2005 (EPAct 2005) established a new section 210(n) of the Public Utility Regulatory Policies Act of 1978 (PURPA), 16 USC 824a-3(n), with additional requirements for any qualifying cogeneration facility that (1) is seeking to sell electric energy pursuant to section 210 of PURPA and (2) was either not a cogeneration facility on August 8, 2005, or had not filed a self-certification or application for Commission certification of QF status on or before February 1, 2006. These requirements were implemented by the Commission in 18 C.F.R. § 292.205(d). Complete the lines below, carefully following the instructions, to demonstrate whether these additional requirements apply to your cogeneration facility and, if so, whether your facility complies with such requirements.	
	11a Was your facility operating as a qualifying cogeneration facility on or before August 8, 2005? Yes No	ن
	11b Was the initial filing seeking certification of your facility (whether a notice of self-certification or an application for Commission certification) filed on or before February 1, 2006? Yes No	Ü
ه ه	If the answer to either line 11a or 11b is Yes, then continue at line 11c below. Otherwise, if the answers to both lines 11a and 11b are No, skip to line 11e below.	
ntal Us acilitie	11c With respect to the design and operation of the facility, have any changes been implemented on or after February 2, 2006 that affect general plant operation, affect use of thermal output, and/or increase net power production capacity from the plant's capacity on February 1, 2006?	
ner n F	Yes (continue at line 11d below)	
ct 2005 Requirements for Fundamental Use Energy Output from Cogeneration Facilities	No. Your facility is not subject to the requirements of 18 C.F.R. § 292.205(d) at this time. However, it may be subject to to these requirements in the future if changes are made to the facility. At such time, the applicant would need to recertify the facility to determine eligibility. Skip lines 11d through 11j.	
s for oger	11d Does the applicant contend that the changes identified in line 11c are not so significant as to make the facility a "new" cogeneration facility that would be subject to the 18 C.F.R. § 292.205(d) cogeneration requirements?	Ö
ements from C	Yes. Provide in the Miscellaneous section starting on page 19 a description of any relevant changes made to the facility (including the purpose of the changes) and a discussion of why the facility should not be considered a "new" cogeneration facility in light of these changes. Skip lines 11e through 11j.	
Require utput 1	No. Applicant stipulates to the fact that it is a "new" cogeneration facility (for purposes of determining the applicability of the requirements of 18 C.F.R. § 292.205(d)) by virtue of modifications to the facility that were initiated on or after February 2, 2006. Continue below at line 11e.	
05.1 y 0	11e Will electric energy from the facility be sold pursuant to section 210 of PURPA?	٥
ct 2005 Energy C	Yes. The facility is an EPAct 2005 cogeneration facility. You must demonstrate compliance with 18 C.F.R. § 292.205(d)(2) by continuing at line 11f below.	. 1980)
EPAc of Er	No. Applicant certifies that energy will <i>not</i> be sold pursuant to section 210 of PURPA. Applicant also certifies its understanding that it must recertify its facility in order to determine compliance with the requirements of 18 C.F.R. § 292.205(d) <i>before</i> selling energy pursuant to section 210 of PURPA in the future. Skip lines 11f through 11j.	
	11f Is the net power production capacity of your cogeneration facility, as indicated in line 7g above, less than or equal to 5,000 kW?	Ú
	Yes, the net power production capacity is less than or equal to 5,000 kW. 18 C.F.R. § 292.205(d)(4) provides a rebuttable presumption that cogeneration facilities of 5,000 kW and smaller capacity comply with the requirements for fundamental use of the facility's energy output in 18 C.F.R. § 292.205(d)(2). Applicant certifies its understanding that, should the power production capacity of the facility increase above 5,000 kW, then the facility must be recertified to (among other things) demonstrate compliance with 18 C.F.R. § 292.205(d)(2). Skip lines 11g through 11j.	
	No, the net power production capacity is greater than 5,000 kW. Demonstrate compliance with the requirements for fundamental use of the facility's energy output in 18 C.F.R. § 292.205(d)(2) by continuing on the next page at line 11g.	

Lines 11g through 11k below guide the applicant through the process of demonstrating compliance with the requirements for "fundamental use" of the facility's energy output. 18 C.F.R. § 292.205(d)(2). Only respond to the lines on this page if the instructions on the previous page direct you to do so. Otherwise, skip this page.

18 C.F.R. § 292.205(d)(2) requires that the electrical, thermal, chemical and mechanical output of an EPAct 2005 cogeneration facility is used fundamentally for industrial, commercial, residential or institutional purposes and is not intended fundamentally for sale to an electric utility, taking into account technological, efficiency, economic, and variable thermal energy requirements, as well as state laws applicable to sales of electric energy from a qualifying facility to its host facility. If you were directed on the previous page to respond to the items on this page, then your facility is an EPAct 2005 cogeneration facility that is subject to this "fundamental use" requirement.

The Commission's regulations provide a two-pronged approach to demonstrating compliance with the requirements for fundamental use of the facility's energy output. First, the Commission has established in 18 C.F.R. § 292.205(d)(3) a "fundamental use test" that can be used to demonstrate compliance with 18 C.F.R. § 292.205(d)(2). Under the fundamental use test, a facility is considered to comply with 18 C.F.R. § 292.205(d)(2) if at least 50 percent of the facility's total annual energy output (including electrical, thermal, chemical and mechanical energy output) is used for industrial, commercial, residential or institutional purposes.

Second, an applicant for a facility that does not pass the fundamental use test may provide a narrative explanation of and support for its contention that the facility nonetheless meets the requirement that the electrical, thermal, chemical and mechanical output of an EPAct 2005 cogeneration facility is used fundamentally for industrial, commercial, residential or institutional purposes and is not intended fundamentally for sale to an electric utility, taking into account technological, efficiency, economic, and variable thermal energy requirements, as well as state laws applicable to sales of electric energy from a qualifying facility to its host facility.

Complete lines 11g through 11j below to determine compliance with the fundamental use test in 18 C.F.R. § 292.205(d)(3). Complete lines 11g through 11j even if you do not intend to rely upon the fundamental use test to demonstrate compliance with 18 C.F.R. § 292.205(d)(2).

11g Amount of electrical, thermal, chemical and mechanical energy output (net of internal generation plant losses and parasitic loads) expected to be used annually for industrial, commercial, residential or institutional purposes and not sold to an electric utility	MWh
11h Total amount of electrical, thermal, chemical and mechanical energy expected to be	MWh
sold to an electric utility 11i Percentage of total annual energy output expected to be used for industrial,	IVIVVN
commercial, residential or institutional purposes and not sold to a utility = 100 * 11g /(11g + 11h)	0 %

11j Is the response in line 11i greater than or equal to 50 percent?

Yes. Your facility complies with 18 C.F.R. § 292.205(d)(2) by virtue of passing the fundamental use test provided in 18 C.F.R. § 292.205(d)(3). Applicant certifies its understanding that, if it is to rely upon passing the fundamental use test as a basis for complying with 18 C.F.R. § 292.205(d)(2), then the facility must comply with the fundamental use test both in the 12-month period beginning with the date the facility first produces electric energy, and in all subsequent calendar years.

No. Your facility does not pass the fundamental use test. Instead, you must provide in the Miscellaneous section starting on page 19 a narrative explanation of and support for why your facility meets the requirement that the electrical, thermal, chemical and mechanical output of an EPAct 2005 cogeneration facility is used fundamentally for industrial, commercial, residential or institutional purposes and is not intended fundamentally for sale to an electric utility, taking into account technological, efficiency, economic, and variable thermal energy requirements, as well as state laws applicable to sales of electric energy from a QF to its host facility. Applicants providing a narrative explanation of why their facility should be found to comply with 18 C.F.R. § 292.205(d)(2) in spite of non-compliance with the fundamental use test may want to review paragraphs 47 through 61 of Order No. 671 (accessible from the Commission's QF website at www.ferc.gov/QF), which provide discussion of the facts and circumstances that may support their explanation. Applicant should also note that the percentage reported above will establish the standard that that facility must comply with, both for the 12-month period beginning with the date the facility first produces electric energy, and in all subsequent calendar years. See Order No. 671 at paragraph 51. As such, the applicant should make sure that it reports appropriate values on lines 11g and 11h above to serve as the relevant annual standard, taking into account expected variations in production conditions.



Usefulness of Topping-Cycle Thermal Output

Information Required for Topping-Cycle Cogeneration Facility

If you indicated in line 10a that your facility represents topping-cycle cogeneration technology, then you must respond to the items on pages 14 and 15. Otherwise, skip pages 14 and 15.

The thermal energy output of a topping-cycle cogeneration facility is the net energy made available to an industrial or commercial process or used in a heating or cooling application. Pursuant to sections 292.202(c), (d) and (h) of the Commission's regulations (18 C.F.R. §§ 292.202(c), (d) and (h)), the thermal energy output of a qualifying topping-cycle cogeneration facility must be useful. In connection with this requirement, describe the thermal output of the topping-cycle cogeneration facility by responding to lines 12a and 12b below.

12a Identify and describe each thermal host, and specify the annual average rate of thermal output made available to each host for each use. For hosts with multiple uses of thermal output, provide the data for each use in separate rows.
Average annual rate of thermal output attributable to use (net of Name of entity (thermal host)
Thermal host's relationship to facility; heat contained in process

taking	thermal output	Thermal host's use of thermal output	return or make-up water)
1)		Select thermal host's relationship to facility	
1)		Select thermal host's use of thermal output	Btu/h
2)		Select thermal host's relationship to facility	
[2]		Select thermal host's use of thermal output	Btu/h
2)		Select thermal host's relationship to facility	
3)		Select thermal host's use of thermal output	Btu/h
4)		Select thermal host's relationship to facility	
(4)		Select thermal host's use of thermal output	Btu/h
[-]		Select thermal host's relationship to facility	
5)		Select thermal host's use of thermal output	Btu/h
		Select thermal host's relationship to facility	
6)		Select thermal host's use of thermal output	Btu/h

Check here and continue in the Miscellaneous section starting on page 19 if additional space is needed

12b Demonstration of usefulness of thermal output: At a minimum, provide a brief description of each use of the thermal output identified above. In some cases, this brief description is sufficient to demonstrate usefulness. However, if your facility's use of thermal output is not common, and/or if the usefulness of such thermal output is not reasonably clear, then you must provide additional details as necessary to demonstrate usefulness. Your application may be rejected and/or additional information may be required if an insufficient showing of usefulness is made. (Exception: If you have previously received a Commission certification approving a specific use of thermal output related to the instant facility, then you need only provide a brief description of that use and a reference by date and docket number to the order certifying your facility with the indicated use. Such exemption may not be used if any change creates a material deviation from the previously authorized use.) If additional space is needed, continue in the Miscellaneous section starting on page 19.

orm 556	Page 15 - Topping	-Cycle Cogeneration Facilities
cycle operating standard and, if applic regulations (18 C.F.R. § 292.205(a)(1)) of the useful thermal energy output must (18 C.F.R. § 292.205(a)(2)) establishes the installation commenced on or after Mathermal energy output must (A) be no facility; and (B) if the useful thermal energy on less than 45 percent of the total compliance with the topping-cycle op	opping-cycle technology must demonstrate compable, efficiency standard. Section 292.205(a)(1) of establishes the operating standard for topping-cycle to be no less than 5 percent of the total energy of the efficiency standard for topping-cycle cogenerarch 13, 1980: the useful power output of the faciless than 42.5 percent of the total energy input ergy output is less than 15 percent of the total energy input of natural gas and oil to the facility erating and/or efficiency standards, or to demonstrated on the date that installation commenced, respectively.	of the Commission's ycle cogeneration facilities: utput. Section 292.205(a)(2) ration facilities for which cility plus one-half the useful of natural gas and oil to the nergy output of the facility, r. To demonstrate estrate that your facility is
technology, then respond to lines 13a attributable to the topping-cycle porti	cility represents <i>both</i> topping-cycle and bottom through 13I below considering only the energy ion of your facility. Your mass and heat balance of the system components are for which portion (top	inputs and outputs diagram must make clear
13a Indicate the annual average rate	of useful thermal energy output made available	D. 4
	ed in condensate return or make-up water	Btu/h
13b Indicate the annual average rate	of net electrical energy output	kW
13c Multiply line 13b by 3,412 to conv		⊖ Btu/h
13d Indicate the annual average rate of the shaft of a prime mover for purposition (this value is usually zero)	of mechanical energy output taken directly off oses not directly related to power production	hp
13e Multiply line 13d by 2,544 to con	vert from hp to Btu/h	0 Btu/h
13f Indicate the annual average rate of	of energy input from natural gas and oil	Btu/h
13g Topping-cycle operating value =	100 * 13a / (13a + 13c + 13e)	0 %
13h Topping-cycle efficiency value =	100 * (0.5*13a + 13c + 13e) / 13f	. 0 %
13i Compliance with operating stand Yes (complies with operating	ard: Is the operating value shown in line 13g groups are standard) \qquad \qqqqqqqqqqqqqqqqqqqqqqqqqqqqqqqqqqqq	
Yes. Your facility is subject to compliance with the efficience	s current form commence on or after March 13, the efficiency requirements of 18 C.F.R. § 292.20 y requirement by responding to line 13k or 13l, a	5(a)(2). Demonstrate as applicable, below.
No. Your facility is exempt fro	m the efficiency standard. Skip lines 13k and 13	l.

13k Compliance with efficiency standard (for low operating value): If the operating value shown in line 13g is less than 15%, then indicate below whether the efficiency value shown in line 13h greater than or equal to 45%:

13I Compliance with efficiency standard (for high operating value): If the operating value shown in line 13g is greater than or equal to 15%, then indicate below whether the efficiency value shown in line 13h is greater than or

Yes (complies with efficiency standard)

Yes (complies with efficiency standard)

equal to 42.5%:

No (does not comply with efficiency standard)

No (does not comply with efficiency standard)

Usefulness of Bottoming-Cycle

Information Required for Bottoming-Cycle Cogeneration Facility

If you indicated in line 10a that your facility represents bottoming-cycle cogeneration technology, then you must respond to the items on pages 16 and 17. Otherwise, skip pages 16 and 17.

The thermal energy output of a bottoming-cycle cogeneration facility is the energy related to the process(es) from which at least some of the reject heat is then used for power production. Pursuant to sections 292.202(c) and (e) of the Commission's regulations (18 C.F.R. § 292.202(c) and (e)), the thermal energy output of a qualifying bottomingcycle cogeneration facility must be useful. In connection with this requirement, describe the process(es) from which at least some of the reject heat is used for power production by responding to lines 14a and 14b below. 14a Identify and describe each thermal host and each bottoming-cycle cogeneration process engaged in by each host. For hosts with multiple bottoming-cycle cogeneration processes, provide the data for each process in separate rows. Has the energy input to the thermal host been Name of entity (thermal host) augmented for purposes performing the process from of increasing power which at least some of the production capacity? reject heat is used for power Thermal host's relationship to facility; (if Yes, describe on p. 19) Thermal host's process type production Select thermal host's relationship to facility No Yes 1) Select thermal host's process type Select thermal host's relationship to facility No 🗌 2) Select thermal host's process type Select thermal host's relationship to facility No 3) Select thermal host's process type Check here and continue in the Miscellaneous section starting on page 19 if additional space is needed 14b Demonstration of usefulness of thermal output: At a minimum, provide a brief description of each process identified above. In some cases, this brief description is sufficient to demonstrate usefulness. However, if your facility's process is not common, and/or if the usefulness of such thermal output is not reasonably clear, then you must provide additional details as necessary to demonstrate usefulness. Your application may be rejected and/or additional information may be required if an insufficient showing of usefulness is made. (Exception: If you have previously received a Commission certification approving a specific bottoming-cycle process related to the instant facility, then you need only provide a brief description of that process and a reference by date and docket number to the order certifying your facility with the indicated process. Such exemption may not be used if any material changes to the process have been made.) If additional space is needed, continue in the Miscellaneous section starting on page 19.

Bottoming-Cycle Operating and Efficiency Value Calculation

(this value is usually zero)

than or equal to 45%:

or oil

15e Multiply line 15d by 2,544 to convert from hp to Btu/h

15g Bottoming-cycle efficiency value = 100 * (15c + 15e) / 15f

Yes (complies with efficiency standard)

15f Indicate the annual average rate of supplementary energy input from natural gas

m 556 Fage 17 - Bottoming	g-Cycle Cogeneration racinties
Applicants for facilities representing bottoming-cycle technology and for which install March 13, 1990 must demonstrate compliance with the bottoming-cycle efficiency stathe Commission's regulations (18 C.F.R. § 292.205(b)) establishes the efficiency standa cogeneration facilities: the useful power output of the facility must be no less than 45 of natural gas and oil for supplementary firing. To demonstrate compliance with the standard (if applicable), or to demonstrate that your facility is exempt from this standard installation of the facility began, respond to lines 15a through 15h below.	ndards. Section 292.205(b) of rd for bottoming-cycle percent of the energy input pottoming-cycle efficiency
If you indicated in line 10a that your facility represents <i>both</i> topping-cycle and bottom technology, then respond to lines 15a through 15h below considering only the energy attributable to the bottoming-cycle portion of your facility. Your mass and heat balan which mass and energy flow values and system components are for which portion of topping or bottoming).	/ inputs and outputs ce diagram must make clear
15a Did installation of the facility in its current form commence on or after March 13,	1980?
Yes. Your facility is subject to the efficiency requirement of 18 C.F.R. § 292.205 with the efficiency requirement by responding to lines 15b through 15h below	(b). Demonstrate compliance v.
No. Your facility is exempt from the efficiency standard. Skip the rest of page	17.
15b Indicate the annual average rate of net electrical energy output	kW
15c Multiply line 15b by 3,412 to convert from kW to Btu/h	0 Btu/h
15d Indicate the annual average rate of mechanical energy output taken directly off of the shaft of a prime mover for purposes not directly related to power production	

15h Compliance with efficiency standard: Indicate below whether the efficiency value shown in line 15g is greater

No (does not comply with efficiency standard)



hp

0 Btu/h

0 %

Btu/h

Certificate of Completeness, Accuracy and Authority

Applicant must certify compliance with and understanding of filing requirements by checking next to each item below and signing at the bottom of this section. Forms with incomplete Certificates of Completeness, Accuracy and Authority will be rejected by the Secretary of the Commission.

Signer identified below certifies the following: (check all items and applicable subitems)

signer identified below tertifies the follow	ving. (check all items and applicable subitems)	
	g any information contained in any attached docu d any information contained in the Miscellaneous s	
He or she has provided all of the requ to the best of his or her knowledge a	uired information for certification, and the provided and belief.	d information is true as stated,
He or she possess full power and autl Practice and Procedure (18 C.F.R. § 38	hority to sign the filing; as required by Rule 2005(a 35.2005(a)(3)), he or she is one of the following: (ch)(3) of the Commission's Rules of leck one)
☐ The person on whose behalf	the filing is made	
$ extstyle oxedsymbol{oxed}$ An officer of the corporation,	trust, association, or other organized group on be	half of which the filing is made
An officer, agent, or employe filing is made	of the governmental authority, agency, or instrum	entality on behalf of which the
	practice before the Commission under Rule 2101 of F.R. § 385.2101) and who possesses authority to si	
He or she has reviewed all automatic Miscellaneous section starting on page	calculations and agrees with their results, unless o	therwise noted in the
interconnect and transact (see lines 4	Form 556 and all attachments to the utilities with la through 4d), as well as to the regulatory authoring the Required Notice to Public Utilities and State Re	ties of the states in which the
Procedure (18 C.F.R. § 385.2005(c)) provid	nture date below. Rule 2005(c) of the Commission' es that persons filing their documents electronical iled documents. A person filing this document ele ided below.	lly may use typed characters
Your Signature	Your address	Date
Leslie A. Freiman	808 Travis Street #700 Houston, TX 77002	12/21/2016
Audit Notes		
Commission Staff Use Only:		

FERC Form 556

Page 19 - All Facilities

Miscellaneous

Use this space to provide any information for which there was not sufficient space in the previous sections of the form to provide. For each such item of information *clearly identify the line number that the information belongs to*. You may also use this space to provide any additional information you believe is relevant to the certification of your facility.

Your response below is not limited to one page. Additional page(s) will automatically be inserted into this form if the length of your response exceeds the space on this page. Use as many pages as you require.

EXHIBIT B REQUIRED FACILITY DOCUMENTS

Sellers Generation Interconnection Agreement

Transmission Service Agreement with PacifiCorp

Purchase option agreement

Conditional Use Permit issued by Lake County

Any additional permits that might be required by Lake County or Oregon Department of Environmental Quality, including access permit, building and electric permits, and storm water prevention permit

FERC Qualifying Facility self-certification

EXHIBIT C START-UP TESTING

VISUAL AND MECHANICAL INSPECTIONS

INVERTER COMMISSIONING

ELECTRICAL OPERATION TESTS

SYSTEM MONITORING VERIFICATION

TRACKER VERIFICATION

INFRARED SCANS

BLOCK TESTING

72-HOUR FUNCTIONAL TEST

GRID MATCH TEST

POWER CHARACTERIZATION

REVENUE METER VERIFICATION

REACTIVE POWER TEST

POWER OUTPUT TEST - PLANT PERFORMANCE AND ACCEPTANCE

EXHIBIT D SCHEDULE

Sheet No. 201-1

SCHEDULE 201 QUALIFYING FACILITY 10 MW or LESS AVOIDED COST POWER PURCHASE INFORMATION

PURPOSE

To provide information about Standard Avoided Costs and Renewable Avoided Costs, Standard Power Purchase Agreements (PPA) and Negotiated PPAs, power purchase prices and price options for power delivered by a Qualifying Facility (QF) to the Company with nameplate capacity of 10,000 kW (10MW) or less.

AVAILABLE

To owners of QFs making sales of electricity to the Company in the State of Oregon (Seller).

APPLICABLE

For power purchased from small power production or cogeneration facilities that are QFs as defined in 18 Code of Federal Regulations (CFR) Section 292, that meet the eligibility requirements described herein and where the energy is delivered to the Company's system and made available for Company purchase pursuant to a Standard PPA.

ESTABLISHING CREDITWORTHINESS

The Seller must establish creditworthiness prior to service under this schedule. For a Standard PPA, a Seller may establish creditworthiness with a written acknowledgment that it is current on all existing debt obligations and that it was not a debtor in a bankruptcy proceeding within the preceding 24 months. If the Seller is not able to establish creditworthiness, the Seller must provide security deemed sufficient by the Company as set forth in the Standard PPA.

POWER PURCHASE INFORMATION

A Seller may call the Power Production Coordinator at (503) 464-8000 to obtain more information about being a Seller or how to apply for service under this schedule.

In accordance with terms set forth in this schedule and the Commission's Rules as applicable, the Company will purchase any Energy in excess of station service (power necessary to produce generation) and amounts attributable to conversion losses, which are made available from the Seller.

A Seller must execute a PPA with the Company prior to delivery of power to the Company. The agreement will have a term of up to 20 years as selected by the QF.

A QF with a nameplate capacity rating of 10 MW or less as defined herein may elect the option of a Standard PPA.

SCHEDULE 201 (Continued)

PPA (Continued)

Any Seller may elect to negotiate a PPA with the Company. Such negotiation will comply with the requirements of the Federal Energy Regulatory Commission (FERC), and the Commission including the guidelines in Order No. 07-360, and Schedule 202. Negotiations for power purchase pricing will be based on either the filed Standard Avoided Costs or Renewable Avoided Costs in effect at that time.

STANDARD PPA (Nameplate capacity of 10 MW or less)

A Seller choosing a Standard PPA will complete all informational and price option selection requirements in the applicable Standard PPA and submit the executed Agreement to the Company prior to service under this schedule. The Standard PPA is available at www.portlandgeneral.com. The available Standard PPAs are:

- Standard In-System Non-Variable Power Purchase Agreement
- Standard Off-System Non-Variable Power Purchase Agreement
- Standard In-System Variable Power Purchase Agreement
- Standard Off-System Variable Power Purchase Agreement
- Standard Renewable In-System Non-Variable Power Purchase Agreement
- Standard Renewable Off-System Non-Variable Power Purchase Agreement
- Standard Renewable In-System Variable Power Purchase Agreement
- Standard Renewable Off-System Variable Power Purchase Agreement

The Standard PPAs applicable to variable resources are available only to QFs utilizing wind, solar or run of river hydro as the primary motive force.

GUIDELINES FOR 10 MW OR LESS FACILITIES ELECTING STANDARD PPA

To execute the Standard PPA the Seller must complete all of the general project information requested in the applicable Standard PPA.

When all information required in the Standard PPA has been received in writing from the Seller, the Company will respond within 15 business days with a draft Standard PPA.

The Seller may request in writing that the Company prepare a final draft Standard PPA. The Company will respond to this request within 15 business days. In connection with such request, the QF must provide the Company with any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft Standard PPA.

When both parties are in full agreement as to all terms and conditions of the draft Standard PPA, the Company will prepare and forward to the Seller a final executable version of the agreement within 15 business days. Following the Company's execution, an executed copy will be returned to the Seller. Prices and other terms and conditions in the PPA will not be final and binding until the Standard PPA has been executed by both parties.

Sheet No. 201-3

SCHEDULE 201 (Continued)

OFF-SYSTEM PPA

A Seller with a facility that interconnects with an electric system other than the Company's electric system may enter into a PPA with the Company after following the applicable Standard or Negotiated PPA guidelines and making the arrangements necessary for transmission of power to the Company's system.

BASIS FOR POWER PURCHASE PRICE

AVOIDED COST SUMMARY

The power purchase prices are based on either the Company's Standard Avoided Costs or Renewable Avoided Costs in effect at the time the agreement is executed. Avoided Costs are defined in 18 CFR 292.101(6) as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."

Monthly On-Peak prices are included in both the Standard Avoided Costs as listed in Tables 1a, 2a, and 3a and Renewable Avoided Costs as listed in Tables 4a, 5a, and 6a. Monthly Off-Peak prices are included in both the Standard Avoided Costs as listed in Tables 1b, 2b, and 3b and Renewable Avoided Costs as listed in Tables 4b, 5b, and 6b.

ON-PEAK PERIOD

The On-Peak period is 6:00 a.m. until 10:00 p.m., Monday through Saturday.

OFF-PEAK PERIOD

The Off-Peak period is 10:00 p.m. until 6:00 a.m., Monday through Saturday, and all day on Sunday.

Standard Avoided Costs are based on forward market price estimates through the Resource Sufficiency Period, the period of time during which the Company's Standard Avoided Costs are associated with incremental purchases of Energy and capacity from the market. For the Resource Deficiency Period, the Standard Avoided Costs reflect the fully allocated costs of a natural gas fueled combined cycle combustion turbine (CCCT) including fuel and capital costs. The CCCT Avoided Costs are based on the variable cost of Energy plus capitalized costs at a 93% capacity factor based on a natural gas price forecast, with prices modified for shrinkage and transportation costs.

Renewable Avoided Costs are based on forward market price estimates through the Renewable Resource Sufficiency Period, the period of time during which the Company's Renewable Avoided Costs are associated with incremental purchases of energy and capacity from the market. For the Renewable Resource Deficiency Period, the Renewable Avoided Costs reflect the fully allocated costs of a wind plant including capital costs.

SCHEDULE 201 (Continued)

PRICING FOR STANDARD PPA

Pricing represents the purchase price per MWh the Company will pay for electricity delivered to a Point of Delivery (POD) within the Company's service territory pursuant to a Standard PPA up to the nameplate rating of the QF in any hour. Any Energy delivered in excess of the nameplate rating will be purchased at the applicable Off-Peak Prices for the selected pricing option.

The Standard PPA pricing will be based on either the Standard or Renewable Avoided Costs in effect at the time the agreement is executed.

The Company will pay the Seller either the Off-Peak Standard Avoided Cost pursuant to Tables 1b, 2b, or 3b or the Off-Peak Renewable Avoided Costs pursuant to Tables 4b, 5b, or 6b for: (a) all Net Output delivered prior to the Commercial Operation Date; (b) all Net Output deliveries greater than Maximum Net Output in any PPA year; (c) any generation subject to and as adjusted by the provisions of Section 4.3 of the Standard PPA; (d) Net Output delivered in the Off-Peak Period; and (e) deliveries above the nameplate capacity in any hour. The Company will pay the Seller either the On-Peak Standard Avoided Cost pursuant to Tables 1a, 2a, or 3a or the On-Peak Renewable Avoided Costs pursuant to Tables 4a, 5a, or 6a for all other Net Output. (See the PPA for defined terms.)

Standard Fixed Price Option 1)

The Standard Fixed Price Option is based on Standard Avoided Costs including forecasted natural gas prices. It is available to all QFs.

This option is available for a maximum term of 15 years. Prices will be as established at the time the Standard PPA is executed and will be equal to the Standard Avoided Costs in Tables 1a and 1b, 2a and 2b, or 3a and 3c, depending on the type of QF, effective at execution. QFs using any resource type other than wind and solar are assumed to be Base Load QFs.

Prices paid to the Seller-under the Standard Fixed Price Option include adjustments for the capacity contribution of the QF resource type relative to that of the avoided proxy resource. Both the Base Load QF resources (Tables 1a and 1b) and the avoided proxy resource, the basis used to determine Standard Avoided Costs for the Standard Fixed Price Option, are assumed to have a capacity contribution to peak of 100%. The capacity contribution for Wind QF resources (Tables 2a and 2b) is assumed to be 5%. The capacity contribution for Solar QF resources (Tables 3a and 3b) is assumed to be 5%.

Prices paid to the Seller under the Standard Fixed Price Option for Wind QFs (Tables 2a and 2b) include a reduction for the wind integration costs in Table 7. However, if the Wind QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the wind integration charges in Table 7, in addition to the prices listed in Tables 2a and 2b, for a net-zero effect.

Portland General Electric Company

Sheet No. 201-5

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

Sellers with PPAs exceeding 15 years will receive pricing equal to the Mid-C Index Price for all years up to five in excess of the initial 15.

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued) Standard Fixed Price Option (Continued)

	TABLE 1a											
					Avoide	ed Costs	D1	oad OF	,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,	.,,		
			Sta	ndard Fix	ed Price	Option fo	or Base I	-oau Gi				
				On	-Peak Fo	recast (\$	(MVV H)		:	:	i	
		i					Jul	Aug	Sep	Oct	Nov	Dec
		Feb	Mar	Apr	May	Jun	23.96	26.96	24.96	23.71	26.71	31.46
Year	Jan	22.46	15.61	14.71	12.46	16.96	27.96	30.96	29.46	27.71	28.71	33.71
2016	28.21	28.21	24.71	20.96	19.46	20.46	29.93	33.37	30.63	28.61	31.86	35.71
2017	29.96	31.11	28.11	22.13	21.28	21.28	31.67	35.08	33.37	31.38	32.52	38.21 40.24
2018	31.71	31.95	27.97	23.70	22.00	23.13	33.34	36,94	35.14	33.04	34.24	
2019	33.94	33.64	29.45	24.95	23.15	24.35	64.61	64.73	64.84	65.48	68,60	68.72
2020	35.74	67.34	65,41	64.69	64.41	64.50	67.04	67.17	67.29	67.83	71.38	71.70
2021	67.43	68.84	68.08	67.13	66.81	66.91	69.31	69.45	69.58	70.12	73.56	73.70
2022	69.01	71.76	70.39	69.19	69.07	69.18	71.35	71.50	71.63	72.20	76.49	76.64
2023	71.95	73.85	72.67	71.29	71.10	71.21	75.30		75.62	75.80	82,57	82.89 88.72
2024	74.17	77.30		74.88	75.02	75.14	81.56	1 74	81.90		89.02	
2025	77.19	85.30		81.28	81.22	81.36		1 -0.00			91.39	91.15
2026	85.18			83.12		83.03		75.00			T	93.55
2027	86.85 89.32			85.46		85.46						98,11
2028	94.06			88.74			1-200					104.76
2029	97.60			92.62					7 94.9			104.7
2030	99.56						1		5 98.7			112.2
2031	103.85								1 101.3		1	+
2032	106.5				01	-			1 103.7			
2033	100.3	-										
2034	111.5			1 105.3								
2035	1400		30 110.1			1			31 110.			
2036					1100							
2037	140.6		03 115.2				-					-
2038	104								02 118.			
2039	404		20 120.						36 120	49 121.	20 132.0	0 1 100.
2040				64 119.	76 119.	31 110.						
204	1 120.											

Sheet No. 201-7

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued) Standard Fixed Price Option (Continued)

					TAB	LE 1b						
					Avoide	d Costs						
			Stan	dard Fixe	d Price (Option fo	r Base L	oad QF				
			- Otal	Off-	Peak For	ecast (\$/	MWH)			:		
								A	Sep	Oct	Nov	Dec
 _	Ion I	Feb	Mar	Apr	May	Jun	Jul 15.74	Aug 20.96	20.96	21.21	23.46	26.71
Year	Jan 25,61	20.71	13.96	11.41	6.31	10.11	15.71	25.21	25.46	24.71	25.71	27.96
2016	25.71	24.21	22.21	15.71	13.71	12.71	19.71 19.71	27.04	26.93	25.35	28.20	30.62
2017	26.17	28,12	25.56	19.46	14.68	12.54	22.83	29.26	29.55	28.67	29.84	32.47
2018	29.84	28.09	25.75	18.15	15.81	14.64	24.27	31.12	31,43	30.50	31.75	34.55
2019	31.75	29.88	27,38	19.28	16.79	15.54	26.07	26.19	26.30	26.94	30.06	30.18
2020	28.88	28.79	26.86	26.15	25.87	25.95	27.75	27.88	28.00	28.54	32,09	32.42
2021	29.73	29.56	28.79	27.85	27.53	29.00	29.14	29.27	29.40	29.95	33.38	33.52
2022	31.78	31.59	30.21	29.01	28,90	30.52	30.66	30.81	30.95	31.51	35.80	35.96
2024	33.48	33.16	31.98	30.60	30.41	33,53	33,70	33.86	34.01	34.19	40.97	41.28
2025	35.58	35.69	34.24	33.27	33.42	38.95	39.15	39.34	39.50	39.95	46.62	46.31
2026	42.77	42.89	40.36	38.87	39.66	39,80	39.77	40.09	40.24	40.74	48.16	47.92
2027	43.63	43.54	41.91	39.89	41.23	41.40	41.25	41.58	41.89	42.59	50.60	49.48 53.20
2028	45.26	45.25	43.90	41.40	43.06	43.24	42.80	43.15	43.70	44.43	53.46	56.9
2029	49.15	49.08	46.32	43.83	46.62	46.79	46.83	47.22	47.34	47.90	56.64	58.1
2030	51.82	51.76	49.09	46.84	47.59	47.77	47.81	48.21	48.33	48.90	57.81	62.1
2031	52.90	52.84	50.11	47.82	50.70	50.89	50.97	51.39	51.50	52.10	61.60	63.7
2032	56.59	56.54	53.31	50.92	52.02	52.21	52.30	52.73	52.84	53.45	1	65.3
2033	58.08	58.03	54.69	52.24 53.52	53.30	53,50	53.59	54.04	54.15	54.77		67.1
2034	59.54		56.03		54.75	54.96		55.52	55.62			68.7
2035	61.18		57.54		56.12	56.33			57.00			70.3
2036	62.67		58,96			57.71			58.39			72.0
2037	64.17					1			59.85			73.
2038	65.73					1						75.
2039	67.09					21.00	62.0					+
2040	68.83			-			5 63.3	6 63.87	63.99	64.7	1 / /0.13	
2041	70.23	3 70.17	66.14	+ 1 03.21	_1							

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued) Standard Fixed Price Option (Continued)

						1 = 20						
					Avoide	LE 2a d Costs			e do me to the same a stant of the		Z - 1	
		.,,			ixed Pric	e Option	for Win	d QF				
			- 5	Candaru i	Peak For	ecast (\$/	MWH)					
				<u></u>	1			· 	<u> </u>	Oct	Nov	Dec
			Mar	Apr	May	Jun	Jul	Aug	Sep	19.87	1101	27.62
Year	Jan	Feb	11.77	10.87	8.62	13.12	20.12	23.12	21.12	23,80	24.80	29.80
2016	24.37	18.62	20.80	17.05	15.55	16.55	24.05	27.05	25.55	24.62	27.87	31.72
2017	26.05	24.30	24.12	18.14	17.29	17.29	25.94	29.38	29.30	27.31	28,45	34.14
2018	27.72	27.12	23.90	19.63	17.93	19.06	27.60	31.01	30.99	28.89	30.09	36.09
2019	29.87	27.88	25.30	20.80	19.00	20.20	29.19	32.79	28.10	28.74	31,86	31.98
2020	31.59	29.49	28.66	27.94	27.66	27,75	27.87	27.99	29.84	30.38	33.93	34.25
2021	30.68	30.59	30,62	29.68	29.36	29.46	29.59	29.72	31.30	31,84	35,28	35.42
2022	31.56	31.39	32.11	30.91	30.79	30.90	31.03	31.17	32.84	33,40	37.70	37.85
2023	33.67	33,48 35.06	33.88	32.49	32.30	32.42	32.56	32.70	35.96	36.14	42.91	43.23
2024	35,38		36.18	35.22	35.36	35.48	35.64	35.81	41,48	41.94	48.60	48.29
2025	37.53	37.64 44.87	42,35	40.86	40.79	40.94	41.13	41.32	42.26	42.76	50.18	49.94
2026	44.75	45.56	43.93	41.91	41.68	41.82	41.79	42.12	43.95	44.65	52.66	51.55
2027	45.65	47.31	45.96	43.46	43.30 ⁻	43.46	43.31	43.64	45.80	46.53	55.57	55.30
2028	47.32	51.18	48.43	45.94	45.16	45.34	44.90	45.25 49.36	49.48	50.04	58.78	59.06
2029	51.25 53.96	53.90	51.23	48.98	48.76	48.93	48.97		50.51	51.08	59.99	60.28
2030		55.02	52.29	50.00	49,77	49.95	49.99		53.68			64.3
2031	55.08 58.77	58.72	-	53.10	52.88	53.07	53.15	-			65,46	66.0
2032	60.35		-		54.29	54.49	54.57				67.09	67.7
2033	61.88	1	-	1		55.84	55.93		+		68.86	69.5
2034	63.54					57.32	57.42				70.46	71.1
2035	65.04			58.72		58.70					72.14	72.8
2036	66.61			60.17					-		2 73.86	74.
2037	68.23											76.
2038	69.64											78.
2039	71.4						-			4 67.3	5 78.84	79.
2040	72.8		2 68.7	9 65.92	2 65.66	65.90	1 00.0					

						LE 2b						
Avoided Costs Standard Fixed Price Option for Wind QF												
			S	tandard I	ixed Pric	e Option	for Wir	ia ur				
				Off-	Peak For	ecast (\$	(MWH)					
								Aug	Sep	Oct	Nov	Dec
		Feb	Mar	Apr	May	Jun	Jul 11.87	17.12	17.12	17.37	19.62	22.87
Year	Jan	16.87	10.12	7.57	2.47	6.27	15.80	21.30	21.55	20.80	21.80	24.05
2016	21.77	20.30	18.30	11.80	9.80	8.80	15.72	23.05	22.94	21.36	24.21	26.63
2017	21.80	24.13	21.57	15.47	10.69	8.55	18.76	25.19	25.48	24.60	25.77	28.40
2018	22.18	24.13	21.68	14.08	11.74	10.57	20.12	26.97	27.28	26.35	27.60	30.40
2019	25.77	25.73	23.23	15.13	12.64	11.39	21.84	21.96	22.07	22.71	25.83	25.95
2020	27.60	24.56	22,63	21.92	21.64	21.72	23,44	23.57	23.69	24.23	27.78	28.11
2021	24.65	25.25	24,48	23.54	23,22	23.32	24.75	24.88	25.01	25.56	28.99	29.13 31.49
2022	25.42	27.20	25,82	24.62	24.51	24.61	26.19	26.34	26.48	27.04	31.33	36.72
2023	27.39 29.01	28.69	27.51	26.13	25.94	26.05	29.14	29.30	29.45	29.63	36.41	41.66
2024	31.02	31.13	29.68	28.71	28.86	28.97 34.30	34.50	- 4 00	34.85	35.30	41.97	43.18
2025	38.12	38.24	35.71	34.22	34.16		35.03		35.50	36.00	43.42	44.65
2026	38.89	38.80	37.17	35.15	34.92	35.06 36.57	36.42		37.06		45.77	48.28
2027	40.43	40.42	39.07		36.40	38.32			38.78			51.90
2028	44.23	44.16	41.40	38.91	38.14	41.77			42.32			52.98
2029	46.80		11.07	41.82	41.60	1			43.21			56.9
2030	47.78		1	42.70					8 46.29			58.4
2031	51.38	71.00	10.40			10.00						
2032	52.77					1						+
2033	54.12											
2034	55.66	_)	2 52.0	2 49.46		70.77						
2035	57.0											
2036	58.4											
2037											-	-
2038								01 56.				-
2039			70 58.7					17 57.	68 57.	80 58.	52 70.0	0 1 .0.
2040	247		98 59.9	95 57.0	JB 50.C	55 1 57.0						

36	anuaru	,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,	•									
						LE 3a						
Avoided Costs Standard Fixed Price Option for Solar QF												
	· ···· · · · · · · · · · · · · · · · ·		s	tandard F	ixed Pric	e Option	TOP SOID	1 (4)				
				On-	Peak For	ecast (\$/	MUVITI			- E		
	i	1		· · · · ·	- -	 	Jul	Aug	Sep	Oct	Nov	Dec
Year	Jan	Feb	Mar	Apr	May	Jun	23.96	26.96	24.96	23.71	26.71	31.46
Year 2016	28.21	22.46	15.61	14.71	12.46	16.96	27.96	30.96	29.46	27.71	28.71	33.71
2017	29.96	28.21	24.71	20.96	19.46	20.46	29.93	33.37	30.63	28.61	31.86	35.71
2018	31.71	31.11	28.11	22.13	21.28	21.28	31.67	35.08	33.37	31.38	32.52	38.21
2019	33.94	31.95	27.97	23.70	22.00	23.13	33.34	36.94	35.14	33.04	34.24	40.24
2019	35.74	33.64	29.45	24.95	23.15	24.35	31.16	31.28	31.39	32.03	35,15	35.27
2021	33.98	33.89	31.96	31.24	30.96		32,94	33.08	33.20	33.74	37.28	37.61
2022	34.92	34.75	33.98	33.04	32.72	32.82	34.44	34.58	34.71	35.26	38.69	38.83
2022	37.09	36.90	35.52	34.32	34.21		36.04	36.19	36.32	36.88	41.18	41.33
2023	38.86	38.54	37.36	35.98	35.79	35.90	39.19	39.36	39.51	39.69	46.46	46.78
2025	41.08	41.19	39.73	38.77	38.92	39.03	44.75	44.94	45.10	45.56	52.22	51.91
2025	48.37	48.49	45.97	44.48	44.42	44.56 45.51	45.48	45,81	45.95	46.45	53.87	53.63
2027	49.34	49.25	47.62	45.61	45.38	47.22	47.07	47,40	47.72	48.41	56.42	55.31
2028	51.08	51.07	49.72	47.22	47.06	49.17	48.73	49.08	49.63	50.36	59.40	59.13
2029	55.08	55.01	52.26	49.77	48.99	52.84	52.88	53.27	53.39	53.95	62.69	62.97
2030	57.87	57.81	55.14	52.89	52.67	53.93	53.98	54.37	54.49	55.06	63.98	64.2
2030	59.07	59.00	56.28		53.76		57.21	57.64	57.75	58.34	67.85	68.3
2032	62.83	62.78	59.56		56,94	57.13 58.62	58.70	59.14	59.25	59.86		70.1
2033	64.49	64.44	61.09		58.42	60.05	60.14		60.70	61,32		71.9
2034	66.10	66.05			59.85	61,62	61.71		62.28			73.8
2035	67.84	67.79	64.20		61.41	63.09			63.77	64.42		75.5
2036	69.43				62.88				65.31			77.3
2037	71.08					-			66.90			79.
2037	72.78											80.7
2039	74.28											82.
2040	76.15						-			72.1	7 83.66	84.4
2041	77.69		4 73.6	1 70.74	70.48	10.72						

					TAB	LE 3b						
	Avoided Costs Standard Fixed Price Option for Solar QF											
		**********	S	tandard F	ixed Pric	e Option	for Sola	r QF				
	Off-Peak Forecast (\$/MWH)											
						· · ·		Aug	Sep	Oct	Nov	Dec
Veer	Jan	Feb	Mar	Apr	May	Jun	Jul 15.71	Aug 20.96	20.96	21.21	23.46	26.71
Year 2016	25.61	20.71	13.96	11.41	6.31	10.11	19.71	25.21	25.46	24.71	25.71	27.96
	25.71	24.21	22.21	15.71	13.71	12.71	19.71	27.04	26.93	25.35	28.20	30.62
2017	26.17	28.12	25.56	19.46	14.68	12.54	22.83	29.26	29.55	28.67	29.84	32.47
2019	29.84	28.09	25.75	18.15	15.81	14.64	24,27	31.12	31.43	30.50	31.75	34.55
2019	31.75	29.88	27.38	19.28	16.79	15.54	26.07	26.19	26.30	26,94	30.06	30.18
	28.88	28.79	26.86	26.15	25.87	25.95	27.75	27.88	28.00	28.54	32.09	32.42
2021	29.73	29.56	28.79	27.85	27.53	27.63	29.14	29.27	29.40	29.95	33,38	33.52
2023	31.78	31.59	30.21	29.01	28.90	29.00	30.66	30.81	30.95	31.51	35.80	35.96
2023	33.48	33.16	31.98	30.60	30.41	33.53	33.70	33.86	34.01	34.19	40.97	41.28
2025	35.58	35.69	34.24	33.27	33.42	38.95	39.15	39.34	39.50	39,95	46.62	46.31
2026	42.77	42.89	40.36	38.87	38.81	39.80	39.77	40.09	40.24	40.74	48.16	47.92
2027	43.63	43.54	41.91	39.89	39.66		41.25	41.58	41.89	42.59	50.60	49.48
2028	45.26	45.25	43.90	41.40	41.23	41.40	42.80	43.15	43.70	44.43	53,46	53.20
2029	49.15	49.08	46.32	43,83	43.06	46.79	46.83	47.22	47.34	47.90	56.64	56.92
2030	51.82	51.76	49.09	46.84	46.62	47.77	47.81	48.21	48.33	48.90	57.81	58.10
2031	52.90	52.84	50.11	47.82	47.59	50.89	50.97	51.39	51.50	52.10	61.60	62.15
2032	56.59	56.54	53.31	50.92	50.70	52.21	52.30	52.73	52.84	53,45	63.19	63.78
2033	58.08	58.03	54.69	52.24	52.02	53.50	53.59	54.04	54.15	54.77	64.76	65.39
2034	59.54	59.50	56.03	53.52	53.30	54.96	55.06	55.52	55.62	56.26	66.50	67.17
2035	61.18			54.98	54.75	56.33	56.43		57.00	57.65	68.09	68.78
2036	62.67	62.62		56.35	56.12	57.71	57.80		58.39	59.06	69.69	70.39
2037	64.17				57.49	59.15	59.25		59.85	60.52		72.08
2038	65.73	65.69			58,93	60.38	+			61.78		73.56
2039	67.09	67.04			T							75.42
2040	68.83	3 68.78							63.99	64.71	76.19	76.95
2041	70.2	3 70.17	66.14	63.27	63.02	05.25	1_50.00					

PRICING OPTIONS FOR STANDARD PPA (Continued)

2) Renewable Fixed Price Option

The Renewable Fixed Price Option is based on Renewable Avoided Costs. It is available only to Renewable QFs that generate electricity from a renewable energy source that may be used by the Company to comply with the Oregon Renewable Portfolio Standard as set forth in ORS 469A.005 to 469A.210.

This option is available for a maximum term of 15 years. Prices will be as established at the time the Standard PPA is executed and will be equal to the Renewable Avoided Costs in Tables 4a and 4b, 5a and 5b, or 6a and 6b, depending on the type of QF, effective at execution. QFs using any resource type other than wind and solar are assumed to be Base Load QFs.

Sellers will retain all Environmental Attributes generated by the facility during the Renewable Resource Sufficiency Period. A Renewable QF choosing the Renewable Fixed Price Option must cede all RPS Attributes generated by the facility to the Company from the start of the Renewable Resource Deficiency Period through the remainder of the PPA term.

Prices paid to the Seller under the Renewable Fixed Price Option include adjustments for the capacity contribution of the QF resource type relative to that of the avoided proxy resource. Both Wind QF resources (Tables 5a and 5b) and the avoided proxy resource, the basis used to determine Renewable Avoided Costs for the Renewable Fixed Price Option, are assumed to have a capacity contribution to peak of 5%. The capacity contribution for Solar QF resources (Tables 6a and 6b) is assumed to be 5%. The capacity contribution for Base Load QF resources (Tables 4a and 4b) is assumed to be 100%.

The Renewable Avoided Costs during the Renewable Resource Deficiency Period reflect an increase for avoided wind integration costs, shown in Table 7.

Prices paid to the Seller under the Renewable Fixed Price Option for Wind QFs (Tables 5a and 5b) include a reduction for the wind integration costs in Table 7, which cancels out wind integration costs included in the Renewable Avoided Costs during the Renewable Resource Deficiency Period. However, if the Wind QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the wind integration charges in Table 7, in addition to the prices listed in Tables 5a and 5b.

Sellers with PPAs exceeding 15 years will receive pricing equal to the Mid-C Index Price for all years up to five in excess of the initial 15.

Rer	rewable	Lixea i	1100 -1									
					TAE	LE 4a	Cocte			and there are a		
	Renewable Avoided Costs Renewable Avoided Costs											
	Drice Ontion to Duos											
	On-Peak Forecast											
							Jul	Aug	Sep	Oct		31.61
:	_	= 1	Mar	Apr	May	Jun	24.11	27.11	25.11	23.86	26.86	33.86
Year	Jan	Feb	15.76	14.86	12.61	17.11	28.11	31.11	29.61	27.86	32.01	35.86
2016	28.36	22.61	24.86	21.11	19.61	20.61	30.08	33.52	30.78	28.76	32.68	38.37
2017	30.11	28.36	28.26	22.28	21.43	21.43	31.83	35.24	33.53	31.54	115.47	114.45
2018	31.86	31.26	28.13	23.86	22.16	23.29	117.01	116.89	115.60	114.63		117.22
2019	34.10	32.11	114.56	115.02	118.22	117.33	119.26	119.77	118.26	117.25	118.55	119.53
2020	115.34	115.32	116.67	117.75	120.59	119.83	121.69	121.65	120.55	119.55	120.98	122.53
2021	117.94	118.18	118.46	120.19	123.17	122.14	124.29	123.92	123.08	121.92	123.63 124.83	124.96
2022	120.48	120.36	120.85	122,92	125.37	124.64	124.23	126.41	126.22	123.83	124.63	127.41
2023	123.26	122.83	123.06	125.07	127.80	126.78		129.66	128.84	126.59	131.17	130.23
2024	124.86	125.01	125.86	128.21	131.66	130,48	100.00	132.69			133.26	
2025	127.73	128.05	129.12	131.30	135.76		104 54	135.95	134.79	131.96	-	in a
2026	130.91	130.58 133.03		133.50	139.48	1	1	1 2 0	5 136.77			-
2027	133.47		132.89	136.24	141.79	T 7.	10.00	-	2 140.86			
2028	135.95	134.91		1	149.30			100	3 144.3	1	1	
2029	138.81	138.57	100 44		153.18		1107		5 146.8		-	
2030	141.68				156.1				1 149.1		-	-
2031	144.29		1 1 1 0					1			-	
2032	146.5	-		_ \			,5		46 155.6			
2033	149.9	-			165.4				31 158.			
2034	152.9				8 168.5			- 1	90 161.			
2035	155.7				5 171.3							
2036	158.3							107	.65 167.			
2037	161.8				5 178.				.89 171		00	
2038	164.9			100 /	6 181.	1 0	170		3.85 174		30	
2039	168.	10			51 185				7.55 177	.80 173.	10 1 1/4	
2040	171.		30		17 188	.98 180	1.12 1.10					
204	1 174.	69 11/4	.00 1									

-	newable				TAB	LE 4b							, v
11- Avoided Costs													
	Renewable Avoided Option for Base Load QF Renewable Fixed Price Option for Base Load QF Off-Peak Forecast (\$/MWH)												
			Kene	Off-	Peak For	recast (\$	(MWH)						
								Avia	Ser	T	Oct	110*	Dec
:	:		Mar	Apr	May	Jun	Jul	Aug 21.11	21.		21.36	23.61	26.86
Year	Jan	Feb	14.11	11.56	6.46	10.26	15.86	25.36	25.		24.86	25.86	28.11
2016	25.76	20.86	22.36	15.86	13.86	12.86	19.86	27.19			25.50	28.35	30.77
2017	25.86	24.36	25.71	19.61	14.83	12.69	19.86	29.42			28.83	30.00	32.63
2018	26.32	28.27	25.91	18.31	15.97	14.80	22.99	61.61		.52	63.74	63.55	63.99
2019	30.00	28.25	64.56	63.31	59.92	60.16	60.45	62.62	-	.78	65.82	63.38	65.09
2020	62.76	63.02	65.85	64.48	61.58	61.62	62.27	63.3		.00	67.04	64.42	66.29
2021	64.93	64.15	67.77	65.49	62.45	62.82	64.33	64.8		.14	68.41	65.38	67.63
2022	65.85	65.52	69.10	67.28	62.84	64.01	65.40	-		6.62	68.68	67.42	68.05
2023	66.70	66.75	70.47	67.09	63.18	65.92	64.75			7.23	70.19	69.68	69.06
2024	67.25	67.31	71.94	68.08	63.17	66.28	66.12			7.05	71.12	69.85	69.89
2025	68.62	68.60	72.28	68,56	63.85	67.22	67.05			8.57	73.22	70.67	71.18
2026	68.95	69.85	73.13	70.34	63.69	68.45		-		0.20	73.79	71.48	73.4
2027	71.31	71.29		T 40	63.09	69.98				1.53	74.58	73.61	74.6
2028	72.28	72.90			58.25	70.29				2.00	75.99		76.2
2029	72.78				58.00					72.16	77.24		76.3
2030	73.91				59.17		_			73.35	78.52		77.5
2031	75.51					71.83			-	74.97	80.25		79.2
2032	76.76				61.48					76.42	81.80		
2033	78.46	1			7 62.66			701-		77.89			
2034	79.9									79.18	84.7		
2035	81.5							-	2.67	80.93			
2036	82.8							10	1,26	82.49	88.3		-
2037			<u> </u>					001	5.89	84.08	90.0		
2038		-	70 1						7:31	85.47	7 91.4		
2039	87.9				66 70.0		10		9.24	87.36	93.5	51 93.3	1 92
2040	89.4		70		59 71.6	85.	55 69	.04			- •		
2041	91.4	44 34.											

		·			TAB	LE 5a						
Ponowable Avoided Costs												
Renewable Fixed Price Option for Wind QF												
	On-Peak Forecast (\$/MWH)											
									Sep	Oct	Nov	Dec
 †	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug 23.27	21.27	20.02		27.77
Year	24.52	18.77	11.92	11.02	8.77	13.27	20.27	27.20	25.70	23.95	24.95	29.95
2016	26.20	24.45	20.95	17.20	15.70	16.70	24.20	29.53	26.79	24.77	28.02	31.87
2017	27.87	27.27	24.27	18.29	17.44	17.44	26.09	31.17	29.46	27.47	28.61	34.30
2019	30.03	28.04	24.06	19.79	18.09	19.22	77.05	76.93	75.64	74.67	75.51	74.49
2020	75.38	75.37	74.61	75.06	78.26	77.37	78.41	78.92	77,41	76.40	77.70	76.38
2021	77.10	77.33	75.83	76.90	79.75	78.99	80.05	80.02	78.92	77.92	79.34	77.90
2021	78.85	78.72	76.82	78,56	81.53	80.51	81.73	81.37	80.53	79.36	81,08	79.97
2023	80.71	80.27	78.29	80.37	82.82	82.08	83.55	83.28	83.10	80.71	81.71	81.84
2024	81.74	81.89	79.93	81.95	84.68	83.66 86.40	85.44	85.57	84.75	82.51	83.68	83.32
2025	83.64	83.97	81.78	84.13	87.57	87.34	87.34	87.75	87.46	84.40	86,23	85.29
2026	85.97	85.64	84.18	86,37	90.82	89.07	88,71	90.15	88.99	86.16	87.45	86.98
2027	87.67	87.23	85.57	87.69	93.67	90.24	90,95	90,96	90.08	88.07	89.15	88,37
2028	89.26	88.22	86,20	89.55	95,10	93,16	93.23	93.23	93.28	89,92	90.73	90.62
2029	91.22	90.98	88.32	91.70	101.72	96.69	94.54	94.42	95.80	91.67	92.24	92.28
2030	93.17	92.88	90.60	93,49	104.67	99.82	96.26	97.20	97.42	93.59	94.70	94.26
2031	94.84	94,34	92.72	96.07	106.65	101.47	97.85	98.80	99.02	95.13	96.26	95.82
2032	96.40	95.90	94.24	97.65	108.40	103.72	100.02	101.00	101.22	97.25	98.40	97.9
2033	98.55	98.03	96.34	99.82	112.94	105.72	101.94	102.94	103.17	99.12	100.29	99.8
2034	100.44		98.19	101.74	112.54	107.76	103.92	104.93	105.16	101.04	102.23	101.7
2035	102.38		100.09	103.71	117.01	109.53	105.61	106.65	106.88	102.69	103.90	103.4
2036	104.06		101.72	105.40	119.61	111.96	107.96	109.02		104.97	106.21	105.7
2037	106.37		103.99		121.92	114.12	110.05	111.12		107.00		107.7
2038	108.42				+		112.17					+
2039	110.52				-	118.23				110.85		
2040	112.32					+			117.95	113.32	114.66	1 114.
2041	114.83	3 114.23	112.26	116.31	120.12	1						

TABLE 5b												
Renewable Avoided Costs												
	Renewable Fixed Price Option for Wind QF											
	Off-Peak Forecast (\$/MWH)											
		:				·	 +		C	Oct	Nov	Dec
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep 17.27	17.52	19.77	23.02
2016	21.92	17.02	10.27	7.72	2.62	6.42	12.02	17.27 21.45	21.70	20.95	21.95	24.20
2017	21.95	20.45	18.45	11.95	9.95	8,95	15.95	23.20	23.09	21.51	24.36	26.78
2018	22.33	24.28	21.72	15.62	10.84	8.70	15.87	25.35	25.64	24.76	25.93	28.56
2019	25.93	24.18	21.84	14.24	11.90	10.73	18.92	57.46	58.37	59.59	59.40	59.84
2020	58.61	58.87	60.41	59.16	55.77	56.01	56.30	58.39	59.55	61.59	59.15	60.86
2021	60.70	59.92	61.62	60.25	57.35	57.39	58.04	59.04	60.69	62.73	60.11	61.98
2022	61.54	61.21	63.46	61.18	58.14	58.51	60.02	60.46	61.75	64,02	60.99	63.24
2023	62.31	62.36	64.71	62.89	58.45	59.62	61.01	60.65	62.15	64.21	62.95	63,58
2024	62.78	62.84	66.00	62.62	58.71	61.45	61.56	62.56	62.67	65.63	65.12	64.50
2025	64.06	64.04	67.38	63.52	58.61	61.72	62.40	63.10	62.40	66.47	65.20	65.24
2026	64.30	65.20	67.63	63,91	59.20	62.57	64.05	63.42	63.83	68.48	65.93	66.44
2027	66.57	66.55	68.39	65.60	58,95	63.71	65.32	63.99	65.37	68,96	66.65	68,58
2028	67.45	68.07	70.58	67.27	58.26	65.15	66.45	65.08	66,61	69.66	68.69	69.76
2029	67.86	68.68	71.87	68.58	53.33	65.37	67.00	67.17	66,98	70.97	70.34	71.21
2030	68.89	69.80	73.34	68.62	52.98	65.87	68.43	68.59	67.04	72,12	71.95	71.19
2031	70.39	71.58	. 74,28	68.88	54.05	65.55 66.62	69.55	69.72	68.14	73.31	73.13	72.36
2032	71.55	72.76	75.50	70.02	54.94	68.11	71.11	71.27	69.66	74.94	74.76	73.98
2033	73.15	74.38	77.19	71.58	56.17	69.42	72.47	72.64	71.00	76.38	76.20	75.40
2034	74.55	75.81	78.67	72.95	57.24 58.35	70.76	73.87	74.05	72,37	77.86	77.67	76,86
2035	76.00	77.28	80.19	74,36		71.91	75.07	75.25	73.55	79.13	78.94	78.11
2036	77.23	78.54	81.50	75.57	59.30 60.62	73.51	76.75	76.93	75.19	80.89	80.70	79.85
2037	78.95	80.29	83.31	77.26	61.79	74.93	78.23	78.41	76.64	82,45	82.26	81.39
2038	80.48	81.84	84.92	78.75	62.99	76.38	79.74	79.93	78.12	84.05	83.85	82.96
2039	82.03	83.42	86.56	80.27	64.01	77,62	81.04	81.23	79.39	85.41	85.21	84.31
2040	83.37	84.77	87.97	81.58	65.44	79.36	82,85		81.17	87.32	87.12	86.20
2041	85.23	86.67	89.94	83.40	05.44	1 / 3.30	1 02,00	1 55.50				

Re	newable	Fixed	1100 0	,								
TABLE 6a												
Renewable Avoided Costs												
Renewable Avoided Renewable Fixed Price Option for Solar QF On-Peak Forecast (\$/MWH)												
				On	-Peak Fo	recast (\$	MAN				New	Dec
							Jul	Aug	Sep	Oct	Nov	31.61
		Fab	Mar	Apr	May	Jun	24.11	27.11	25.11	23.86	26.86	33.86
Year	Jan	Feb 22.61	15.76	14.86	12.61	17.11	28.11	31.11	29.61	27.86	28.86	35.86
2016	28.36	28.36	24.86	21.11	19.61	20.61	30.08	33.52	30.78	28.76	32.68	38.37
2017	30.11	31.26	28.26	22.28	21.43	21.43	31.83	35.24	33.53	31.54		77.73
2018	31.86	32.11	28.13	23.86	22.16	23.29	80.29	80.17	78.88	77.91	78.74	79.67
2019	34.10	78.60	77.84	78.30	81.50	80.60	81.71	82.22	80.71	79.70	81.00 82.70	81.25
2020	78.62	80.63	79.12	80.20	83.04	82.28	83.41	83.38	82.27	81.27		83.39
2021	80,39	82.08	80.18	81.92	84.89	83.87	85.15	84.78	83.94		84.50 85.19	85.32
2022	82.21	83.69	81.71	83.78	86,23	85.50	87.03	86.76	86.58		-	86.87
2023	84,12		83.41	85.43	88.16		88.99		88.30			88.9
2024	85.22	50	15.00	87.68	91.12		90.96		91.08			
2025	87.19		1 200			70	92.40		92.6	89.85		
2026	89.59	1 22 00	20.00			- 4 00	1					
2027	91.36		1 20 00	1 00 04	98.86				_ 1 ~ ~ 4	1 93.75		
2028	93.02		-			_1		~	3 99.7			
2029	95.0	20.7/	24.5		0 108.5		100.0		9 101.4			-
2030	97.0				5 110.6			-				
2031	98.8	-			1 112.4		1		14 105.			
2032	100.4				5 114.9		1-1-0	-	16 107.			
2033		100				\		-	23 109.			
2034	104.6		104		01 119.4				04 111.			
2035	106.6	-			79 121.				49 113			
2036	108.		100				-		.68 115			
2037	110.	<u></u>								1.16 113.		
203	8 112.							<u></u>	.86 120).11 115.		
203	9 115.				.51 131					2.76 118	.14 119	.40 111
204	0 117				.13 133	.94 125.	00 1 121	.01				
204	1 119	.65 119	.00 117	<u>:</u>								

L/c	enewable					ı E Ch						
	TABLE 6b Renewable Avoided Costs											
	Renewable Avoided Renewable Fixed Price Option for Solar QF Renewable Fixed Price Option for Solar QF											
	Renewable Fixed Fine Option Off-Peak Forecast (\$/MWH)											
				Off	Peak For	ecast (4			:		Nave	Dec
					12	Jun	Jul	Aug	Sep	Oct	100	26.86
Year	Jan	Feb	Mar	Apr	May	10.26	15.86	21.11	21.11	21.36	20.0	28.11
	25.76	20.86	14.11	11.56	6.46	12.86	19.86	25.36	25.61	24.86	28.35	30.77
2016	25,86	24.36	22.36	15.86	13.86	12.69	19.86	27.19	27.08	25.50	30.00	32.63
2018	26.32	28.27	25.71	19.61	14.83	14.80	22,99	29.42	29.71	28.83		63.99
2019	30.00	28.25	25.91	18.31	15.97	60.16	60.45	61.61	62.52	63.74	63.55	65.09
	62.76	63.02	64.56	63.31	59.92	61.62	62,27	62.62	63.78	65.82	63.38	66.29
2020	64.93	64.15	65.85	64.48	61.58	62,82	64.33	63.35	65.00	67.04	64.42	67.63
2021	65.85	65.52	67.77	65.49	62.45	64.01	65.40	64.85	66.14	68.41	65.38	68.05
2022	66,70	66.75	69,10	67.28	62.84	65.92	64.75	65.12	66.62	68.68	67.42	69.06
2023	67.25	67.31	70.47	67.09	63.18	66.28	66.12	67.12	67.23	70.19	69.68	69.89
2024	68.62	68.60	71.94	68.08	63.17	67.22	67.05		67.05	71.12	69.85	71.18
2025	68.95	69.85	72.28	68.56	63.85	68.45	68.79		68.57	73.22	70.67	73.41
2026	71.31	71.29	73.13	70.34	63.69	69.98	70,15		70.20	73.79	71.48	74.68
2027	72.28	72.90		72.10		70.29	71.37		71.53		73.61	76.2
2028	72.78	73,60									75.36	76.3
2029	73.91								72.16			77.5
2030	75.51			74.00							1	
2031	76.76				- 1 10							79.2 80.8
2032	78.46								6 76.4		-	82.3
2033	79.97								7 77.8			83.
2034	81.52								8 79.1			85.
2035	82.8	-							7 80.9			87.
2036	84.6								26 82.4			
2037				77 84.6			<u> </u>	70				88.
2038												
2039										36 93.5	1 93.31	92
2040				13 89.	59 71.6	3 85.5	00.	<u>V.</u>				

WIND INTEGRATION

	- 7		
TABI Wind Inte			
	C	ost	
Year		3.77	
2015		3.84	
2016		3.91	
2017		3.99	
2018		4.07	
2019		4.15	
2020		4.23	
2021		4.31	
2022		4.39	
2023	-	4.47	
2024	+	4.56	
2025	+	4.65	
2026	+-	4.74	
2027	+	4.83	1
2028	+	4.92	1
2029	+	5.02	1
2030	+	5.12	1
2031		5.21	1
2032		5.31	1
2033	+	5.42	
2034		5.52	~~
2035		5.63	
2036		5.74	
2037		5.85	-1
2038		5.96	
2039		6.0	
204	ا_ر	0.0	

MONTHLY SERVICE CHARGE

Each separately metered QF not associated with a retail Customer account will be charged \$10.00 per month.

INSURANCE REQUIREMENTS

The following insurance requirements are applicable to Sellers with a Standard PPA:

- QFs with nameplate capacity ratings greater than 200 kW are required to secure and maintain a prudent amount of general liability insurance. The Seller must certify to the Company that it is maintaining general liability insurance coverage for each QF at prudent 1) amounts. A prudent amount will be deemed to mean liability insurance coverage for both bodily injury and property damage liability in the amount of not less than \$1,000,000 each occurrence combined single limit, which limits may be required to be increased or decreased by the Company as the Company determines in its reasonable judgment, that economic conditions or claims experience may warrant.
- Such insurance will include an endorsement naming the Company as an additional insured insofar as liability arising out of operations under this schedule and a provision that such liability policies will not be canceled or their limits reduced without 30 days' written notice to 2) the Company. The Seller will furnish the Company with certificates of insurance together with the endorsements required herein. The Company will have the right to inspect the original policies of such insurance.
- QFs with a design capacity of 200 kW or less are encouraged to pursue liability insurance on their own. The Oregon Public Utility Commission in Order No. 05-584 determined that it is inappropriate to require QFs that have a design capacity of 200 kW or less to obtain general 3) liability insurance.

TRANSMISSION AGREEMENTS

If the QF is located outside the Company's service territory, the Seller is responsible for the transmission of power at its cost to the Company's service territory.

INTERCONNECTION REQUIREMENTS

Except as otherwise provided in a generation Interconnection Agreement between the Company and Seller, if the QF is located within the Company's service territory, switching equipment capable of isolating the QF from the Company's system will be accessible to the Company at all times. At the Company's option, the Company may operate the switching equipment described above if, in the sole opinion of the Company, continued operation of the QF in connection with the utility's system may create or contribute to a system emergency.

INTERCONNECTION REQUIREMENTS (Continued)

The QF owner interconnecting with the Company's distribution system must comply with all requirements for interconnection as established pursuant to Commission rule, in the Company's Rules and Regulations (Rule C) or the Company's Interconnection Procedures contained in its FERC Open Access Transmission Tariff (OATT), as applicable. The Seller will bear full responsibility for the installation and safe operation of the interconnection facilities.

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE PRICING UNDER THE STANDARD PPA

A QF will be eligible to receive pricing under the Standard PPA if the nameplate capacity of the QF, together with any other electric generating facility using the same motive force, owned or controlled by the Same Person(s) or Affiliated Person(s), and located at the Same Site, does not exceed 10 MW. A Community-Based or Family-Owned QF is exempt from these restrictions.

Definition of Community-Based

- a. A community project (or a community sponsored project) must have a recognized and established organization located within the county of the project or within 50 miles of the project that has a genuine role in helping the project be developed and must have some not insignificant continuing role with or interest in the project after it is completed and placed in service.
- b. After excluding the passive investor whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit, the equity (ownership) interests in a community sponsored project must be owned in substantial percentage (80 percent or more) by the following persons (individuals and entities): (i) the sponsoring organization, or its controlled affiliates; (ii) members of the sponsoring organization (if it is a membership organization) or owners of the sponsorship organization (if it is privately owned); (iii) persons who live in the county in which the project is located or who live a county adjoining the county in which the project is located; or (iv) units of local government, charities, or other established nonprofit organizations active either in the county in which the project is located or active in a county adjoining the county in which the project is located.

Definition of Family-Owned

After excluding the ownership interest of the passive investor whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit, five or fewer individuals own 50 percent or more of the equity of the project entity, or fifteen or fewer individuals own 90 percent or more of the project entity. A "look through" rule applies to closely held entities that hold the project entity, so that equity held by LLCs, trusts, estates, corporations, partnerships or other similar entities is considered held by the equity owners of the look through entity. An individual is a natural person. In counting to five or fifteen, spouses or children of an equity owner of the project owner who also have an equity interest are aggregated and counted as a single individual.

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE PRICING UNDER THE STANDARD PPA (Continued)

Definition of Person(s) or Affiliated Person(s)

As used above, the term "Same Person(s)" or "Affiliated Person(s)" means a natural person or persons or any legal entity or entities sharing common ownership, management or acting jointly or in concert with or exercising influence over the policies or actions of another person or entity. However, two facilities will not be held to be owned or controlled by the Same Person(s) or Affiliated Person(s) solely because they are developed by a single entity.

Furthermore, two facilities will not be held to be owned or controlled by the Same Person(s) or Affiliated Person(s) if such common person or persons is a "passive investor" whose ownership interest in the QF is primarily related to utilizing production tax credits, green tag values and MACRS depreciation as the primary ownership benefit and the facilities at issue are independent family-owned or community-based projects. A unit of Oregon local government may also be a "passive investor" in a community-based project if the local governmental unit demonstrates that it will not have an equity ownership interest in or exercise any control over the management of the QF and that its only interest is a share of the cash flow from the QF, which share will not exceed 20%. The 20% cash flow share limit may only be exceeded for good cause shown and only with the prior approval of the Commission.

Definition of Same Site

For purposes of the foregoing, generating facilities are considered to be located at the same site as the QF for which qualification for pricing under the Standard PPA is sought if they are located within a five-mile radius of any generating facilities or equipment providing fuel or motive force associated with the QF for which qualification for pricing under the Standard PPA is sought.

Definition of Shared Interconnection and Infrastructure

QFs otherwise meeting the above-described separate ownership test and thereby qualified for entitlement to pricing under the Standard PPA will not be disqualified by utilizing an interconnection or other infrastructure not providing motive force or fuel that is shared with other QFs qualifying for pricing under the Standard PPA so long as the use of the shared interconnection complies with the interconnecting utility's safety and reliability standards, interconnection agreement requirements and Prudent Electrical Practices as that term is defined in the interconnecting utility's approved Standard PPA.

OTHER DEFINITIONS

Mid-C Index Price

As used in this schedule, the daily Mid-C Index Price shall be the Day Ahead Intercontinental Exchange ("ICE") for the bilateral OTC market for energy at the Mid-C Physical for Average

Sheet No. 201-23

SCHEDULE 201 (Continued)

OTHER DEFINITIONS (Continued)

On-Peak Power and Average Off-Peak Power found on the following website: https://www.theice.com/products/OTC/Physical-Energy/Electricity. In the event ICE no longer publishes this index, PGE and the Seller agree to select an alternative successor index representative of the Mid-C trading hub.

Definition of RPS Attributes

As used in this schedule, RPS Attributes means all attributes related to the Net Output generated by the Facility that are required in order to provide PGE with "qualifying electricity," as that term is defined in Oregon's Renewable Portfolio Standard Act, Ore. Rev. Stat. 469A.010, in effect at the time of execution of this Agreement. RPS Attributes do not include Environmental Attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity and not needed to ensure that there are zero net emissions associated with the generation of electricity.

Definition of Environmental Attributes

As used in this schedule, Environmental Attributes shall mean any and all claims, credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical, or other substance to the air, soil or water. Environmental Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil, or water such as (subject to the foregoing) sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; and (2) any avoided emissions of carbon dioxide (CO2), methane (CH4), and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere.

Definition of Resource Sufficiency Period

This is the period from the current year through 2020.

Definition of Resource Deficiency Period

This is the period from 2021 through 2034.

Definition of Renewable Resource Sufficiency Period

This is the period from the current year through 2019.

Definition of Renewable Resource Deficiency Period

This is the period from 2020 through 2034.

SCHEDULE 201 (Concluded)

DISPUTE RESOLUTION

Upon request, the QF will provide the purchasing utility with documentation verifying the ownership, management and financial structure of the QF in reasonably sufficient detail to allow the utility to make an initial determination of whether or not the QF meets the above-described criteria for entitlement to pricing under the Standard PPA.

The QF may present disputes to the Commission for resolution using the following process:

The QF may file a complaint asking the Commission to adjudicate disputes regarding the formation of the standard contract. The QF may not file such a complaint during any 15-day period in which the utility has the obligation to respond, but must wait until the 15-day period has passed.

The utility may respond to the complaint within ten days of service.

The Commission will limit its review to the issues identified in the complaint and response, and utilize a process similar to the arbitration process adopted to facilitate the execution of interconnection agreements among telecommunications carriers. See OAR 860, Division 016. The administrative law judge will not act as an arbitrator.

SPECIAL CONDITIONS

- Delivery of energy by Seller will be at a voltage, phase, frequency, and power factor as specified by the Company.
- If the Seller also receives retail Electricity Service from the Company at the same location, any payments under this schedule will be credited to the Seller's retail Electricity Service bill.
 At the option of the Customer, any net credit over \$10.00 will be paid by check to the Customer.
- Unless required by state or federal law, if the 1978 Public Utility Regulatory Policies Act (PURPA) is repealed, PPAs entered into pursuant to this schedule will not terminate prior to the Standard or Negotiated PPA's termination date.

TERM OF AGREEMENT

Not less than one year and not to exceed 20 years.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM 1829, UM 1830, UM 1831, UM 1832, UM 1833

BLUE MARMOT V LLC (UM 1829))
BLUE MARMOT VI LLC (UM 1830))
BLUE MARMOT VII LLC (UM 1831))
BLUE MARMOT VIII LLC (UM 1832))
BLUE MARMOT IX LLC (UM 1833))
Complainants)
VS.)
PORTLAND GENERAL ELECTRIC)
COMPANY)
Defendant)
Pursuant to ORS 756.500.)
)

OPENING TESTIMONY OF

KEEGAN MOYER

ON BEHALF OF THE
BLUE MARMOT V, VI, VII, VIII, AND IX

October 13, 2017

		Moyer/1
1	I.	INTRODUCTION
2	Q.	Mr. Moyer, please state your name and business address.
3	A.	My name is Keegan Moyer. My business address is 215 South State Street, Suite
4		200, Salt Lake City, Utah, 84111.
5	Q.	By whom are you employed and in what capacity?
6	A.	I am a Principal in the firm of Energy Strategies, LLC ("Energy Strategies").
7		Energy Strategies is an independent energy consulting firm specializing in
8		economic and policy analysis applicable to energy production, transportation, and
9		consumption.
10 11	Q.	Please describe your professional responsibilities, background, and experience.
12	A.	As a Principal with Energy Strategies, where I have been employed since 2014, I
13		assist private and public sector clients in the areas of electric transmission,
14		generation, and energy-related economic and public policy analyses. In that
15		capacity, I specialize in transmission system analysis and strategy for power
16		generation and transmission projects. I have performed numerous technical and
17		economic assessments of transmission and generation projects and have a strong
18		understanding of power markets, system planning, and the services that allow
19		power to interconnect and move across the transmission system.
20		Prior to joining Energy Strategies, I was the Manager of Transmission

Expansion Planning at the Western Electricity Coordinating Council ("WECC").

In that role, I was responsible for regional transmission assessments and the

development of transmission plans for the Western Interconnection. I was

responsible for providing leadership and direction to the WECC Transmission

21

22

23

24

Expansion Planning Department, facilitating Transmission Expansion Planning
Policy Committee stakeholder activities, and managing the \$14.5 million
Department of Energy Regional Transmission Expansion Planning Grant. I also
advised WECC senior management on the Federal Energy Regulatory
Commission ("FERC") Order 1000 and other relevant energy and planning
policies.

In addition to my transmission policy background, I have extensive technical experience designing and conducting production cost model and power flow simulation studies, and providing policy-oriented analyses of complex power system issues. I regularly deal with FERC-approved Open Access Transmission Tariffs, qualified facilities ("QFs"), interconnection and transmission analyses, and support clients in navigating generation interconnection, transmission service, and transmission planning processes.

My academic background is in both engineering and business management. I have completed a Master of Science in Engineering and Technology Management and a Bachelor of Science in Engineering with Mechanical Specialty, both at the Colorado School of Mines.

In connection with my testimony in this docket, I am familiar with the relevant transmission systems, obligations of QFs as it relates to transmission and interconnection, avoided cost pricing, and the types and nature of transmission service available under Portland General Electric Company's ("PGE") transmission function's ("PGE Transmission") Open Access Transmission Tariff.

1 2	Q.	Have you testified previously before any other state utility regulatory commissions?
3	A.	Yes. I have testified regarding transmission issues before the Colorado Public
4		Utilities Commission and the Utah Public Service Commission.
5	Q.	On whose behalf are you appearing in this proceeding?
6	A.	Blue Marmot V, VI, VII, VIII and IX ("Blue Marmots").
7	Q.	Please summarize your testimony.
8	A.	The Blue Marmot QFs have signed power purchase agreements ("PPAs") to sell
9		their output to PGE under the Public Utility Regulatory Policies Act ("PURPA").
10		As "off-system" QFs, the Blue Marmots have arranged for transmission service
11		that will allow them to deliver the QF output to PGE's system. However, PGE's
12		merchant function ("PGE Merchant") is refusing to counter-sign the Blue Marmot
13		PPAs on account of transmission constraints on PGE Transmission's system at
14		the location where the Blue Marmots have arranged to deliver the power. PGE
15		Merchant's refusal to execute the PPAs is not consistent with the requirements of
16		PURPA and how off-system QFs are handled in Oregon and by FERC. I spend
17		the majority of my testimony explaining why this is the case, while also
18		discussing practical transmission options that could be implemented that would
19		allow PGE Merchant to effectively and efficiently discharge their PURPA
20		responsibilities to accept and manage the QF net output at the location the Blue
21		Marmots have identified.
22		In addition, I address the notion that the Blue Marmots should be held
23		responsible for potential costs to upgrade PGE's transmission system to further

facilitate their delivery, which would have the effect of altering the Blue

24

Marmots' avoided cost rates available at the time the Blue Marmots established legally enforceable obligations ("LEOs").

Lastly, I review two potential discrimination issues at play that appear to be working against the Blue Marmot projects. The first relates to how PGE Merchant is handling the Blue Marmot QFs relative to other QFs with similar transmission arrangements and contractual obligations, and the other considers PGE Merchant's inability to act objectively and fairly when there is a parallel need to reserve transmission for itself and QFs at the same location.

9 II. PURPA OBLIGATIONS

A.

10 Q. Please summarize this portion of your testimony.

The Blue Marmots have satisfied their obligations to sell their net output to PGE as QFs under PURPA. While I am not a lawyer, I will explain my understanding of a QF's obligations under PURPA, and then explain why the Blue Marmots have met these obligations.

The Blue Marmots are only obligated to arrange for delivery to a point of delivery ("POD") on PGE Transmission's system, after which PGE Merchant is required to make transmission arrangements to accept and manage the power.

PGE Merchant, however, has refused to purchase the Blue Marmots' net output and is instead demanding that they pay for transmission upgrades on PGE Transmission's system or deliver their net output to a POD on PGE Transmission's system that has sufficient long-term Available Transfer Capability ("ATC"). PGE Merchant should be barred from raising these obstacles, and should be required to purchase their net output because the Blue Marmots have

1 satisfied their QF obligations by obtaining firm transmission service to PGE 2 Transmission's system as required under PGE's Schedule 201.¹ In addition, I will explain what PGE Merchant should have done instead 3 4 of refusing to purchase the Blue Marmots' net output, which is to accept the 5 power and manage it like their other generation resources or market purchases. 6 PGE Merchant is inappropriately attempting to push its PURPA obligations to 7 accept and manage the Blue Marmots' net output back on to the Blue Marmots. 8 The Blue Marmots are not required to manage PGE's system or identify all the 9 solutions that PGE could consider, but I have identified some options that PGE 10 could have and may still implement to remedy the situation. These include: 11 (1) PGE Merchant converting or otherwise managing existing transmission rights to enable and appropriately prioritize the delivery of OF output to 12 13 their network loads, which could include reducing its own generation or 14 market purchases to accommodate the QF power within those rights; 15 16 (2) PGE Merchant making alternative transmission arrangements on other 17 third-party transmission systems to deliver the QF output to a location of 18 PGE's choosing; or 19 20 (3) PGE Merchant requesting and paying for PGE Transmission to construct 21 network transmission upgrades. 22 23 In the end, it is not the Blue Marmots' responsibility to manage PGE's 24 operations, and there may be more cost-effective ways for PGE Merchant to

accept the QF power and fulfill its PURPA obligations.

25

See e.g., Blue Marmot/202, Talbott/44 (PGE Schedule 201 attached to Blue Marmot V executed Power Purchase Agreement Sheet No. 201-3: "...and making the arrangements necessary for transmission of power to the Company's [PGE] system.").

1	Q.	Is PGE required to purchase the net output of the Blue Marmots' electric
2		generation?

Yes. Each of the Blue Marmot projects are QFs under PURPA, which obligates

PGE Merchant to purchase each Blue Marmot project's net output. My

understanding is that PGE Merchant does not dispute that it is obligated in

principle to purchase the Blue Marmots' generation. Instead, PGE Merchant is

refusing to purchase the output at the POD on PGE Transmission's system that

the Blue Marmots have identified, and is requiring the Blue Marmots to deliver to

a different POD or pay for transmission upgrades to PGE's system.

10 Q. What is your understanding of a QF's obligation to deliver power to a utility under PURPA?

A.

PGE is obligated to purchase a QF's net output regardless of whether a QF is directly interconnected to the purchasing utility (which in Oregon is called an "on-system QF") or is interconnected with a different utility and wheeling its net output over a third party's transmission system (which in Oregon is called an "off-system QF") to the purchasing utility. My understanding is that the characterization of the Blue Marmots as "on-system" or "off-system" projects is irrelevant to the matter at hand because PGE Merchant must purchase a QF's net output, whether the power is delivered within or wheeled to the PGE system. An off-system QF has the discretion to choose to sell to a purchasing utility that is different than the utility to which the project will interconnect, and thus has the discretion to choose where to locate its project, as long as the QF can deliver its power to the purchasing utility's system from its interconnection point.

Therefore, a QF's responsibility is limited to delivering its power to the point of interconnection ("POI") in the case of an on-system QF, or to a POD on the

1		utility's system for an off-system QF, and the purchasing utility's responsibility is
2		to buy that power, make any necessary arrangements to deliver that power to its
3		load, or otherwise manage the power.
4 5	Q.	Can you explain what you mean by a QF only needing to deliver its power to PGE's POI or POD?
6	A.	Yes. A QF is not required to obtain transmission service, either for itself or on
7		behalf of the purchasing utility, to deliver its energy from the POI or POD with
8		the purchasing utility to the purchasing utility's load. In addition, the purchasing
9		utility cannot curtail the QF's energy except under very limited circumstances.
10	Q.	Does this also apply to an off-system QF, like the Blue Marmots?
11	A.	Yes. Off-system QFs like the Blue Marmots only need to deliver their power to a
12		POD that connects the purchasing utility to the transmitting utility. The only
13		restriction on an off-system QF's ability to sell power to a utility other than the
14		utility to which it is interconnecting is whether the QF can make the necessary
15		arrangements to deliver its power from the POI to the purchasing utility's system.
16		The off-system QF does not need to transmit the power to the purchasing utility's
17		load, but only to the point of change of ownership where the two utilities'
18		transmission systems interconnect. Furthermore, QFs are not restricted to
19		delivering power to a specific POD. The purchasing utility must accept an off-
20		system QF's output at any delivery point on its transmission system.
21 22 23	Q.	Have the Blue Marmots satisfied the requirement to deliver power to the POD of their choosing, and thus required PGE to buy that power and deliver to its load or otherwise manage the power?
24	A.	Yes. As explained by Mr. Talbott, the Blue Marmots will be interconnected with
25		PacifiCorp and have executed transmission service agreements to purchase firm

point-to-point transmission service from PacifiCorp to deliver the net output of the QF projects to PGE at the "PACW.PGE" POD. This means that the Blue Marmots have reserved capacity on PacifiCorp's system to deliver their net output to PGE at the point of change of ownership between PacifiCorp and PGE. PGE Merchant agrees that the PACW.PGE POD is located on its system,² and the PACW.PGE POD is the only point on PGE's transmission system where PGE can receive delivery of power directly from PacifiCorp's transmission system.

Contrary to PURPA requirements, PGE Merchant contends that it is willing to accept the Blue Marmots' delivery at a POD of *its* choosing, namely where PGE Transmission and Bonneville Power Administration's ("BPA") transmission systems interconnect. However, this would require Blue Marmot to incur significant, unnecessary transmission charges to move power from PacifiCorp's system, through BPA's system to the POD where BPA and PGE intersect (BPAT.PGE). The problem with PGE Merchant's request is that the Blue Marmots are not obligated to obtain transmission service for themselves or on behalf of PGE Merchant on PGE's transmission system, or in this case on BPA's transmission system to accommodate PGE Merchant's transmission requests. Instead, the Blue Marmots have the choice to sell their power to PGE at the specific point of their choosing where ownership of the transmission between PacifiCorp and PGE changes.

Blue Marmot/301, Moyer/26-28 (PGE Response to Blue Marmot Data Request ("DR") 44-46).

Ultimately, the Blue Marmots have satisfied their QF obligations by
obtaining the necessary transmission arrangements to deliver their power to the
PGE system at the PACW.PGE POD (the interface point between PGE's and
PacifiCorp's transmission systems), because the Blue Marmots are not required to
deliver QF power to PGE Merchant's preferred POD, and certainly are not
obligated to incur additional costs to wheel the power on other third-party systems
to accommodate PGE's preferences.
Are you aware of any exceptions to PGE's mandatory purchase obligation?

Yes, but they do not apply here.³ There are two general categories of exceptions:

1) exceptions that allow a utility to refuse to enter into a QF PPA; and 2)

exceptions that allow a utility to temporarily refuse to purchase the output from an

operating QF project. Neither category applies to the Blue Marmots.

The first category, which allows utilities to avoid PURPA obligations entirely, including executing PPAs, applies only if QFs have nondiscriminatory access to competitive markets in which they can meaningfully sell their capacity and electric energy output. This exception can only be established through FERC filings and approvals. Since Oregon QFs do not have access to competitive markets and PacifiCorp and PGE have not made these filings, this exception does not apply.

The second category of exceptions are temporary in nature and apply to QFs that are *already operating* under a PPA. One allowable exception under this

Q.

A.

³ 18 CFR 292.304(f);18 CFR 292.307(b).

1 category authorizes a utility to not purchase a QF project's net output during any 2 limited period when there is a system emergency. 3 Another temporary exception for operating QFs allows a utility to curtail a 4 QF's net output during specific operational circumstances during which accepting 5 unscheduled OF output would require reductions in the output of base load 6 generation units due to light load conditions. 7 Q. Do any of these exceptions allow PGE Merchant to issue a blanket refusal to 8 even enter into a power purchase agreement? 9 A. No. As explained above, the Blue Marmots do not have access to competitive 10 markets and exceptions for system emergencies and light load conditions only 11 apply during specific periods of time when the QF is operational. Thus, these 12 provisions cannot be used as justification for PGE Merchant's refusal to execute 13 contracts with the Blue Marmots. 14 Q. Please explain what is meant by system emergency conditions. 15 Α. A system emergency is when there is an imminent risk of significant disruption of 16 service to customers or danger to life or property. A system emergency occurs 17 when the transmission system is operating within its planned limits with sufficient 18 transfer capability, but there is an unplanned or unusual event that requires the

transmission provider to curtail electricity to prevent the system emergency.

19

- 1 Q. Does PGE claim that there would be system emergencies if it accepted the Blue Marmots' net output?
- Yes. PGE Merchant claims that accepting the delivery of Blue Marmot's output could harm system reliability by resulting in usage of the path above its total transfer capability which could be detrimental to system reliability.⁴

6 Q. Do you agree with PGE?

14

No. PGE Merchant is describing a situation in which PGE accepts the Blue

Marmots' net output without otherwise operating its system as a reasonable or

prudent utility. As explained below, PGE Merchant has options for accepting the

Blue Marmots' net output without causing system emergencies by either

increasing the total transfer capability of the relevant path or staying within the

existing transfer capability on its system by managing existing transmission

capacity differently.

Q. Please explain what is meant by light load conditions.

15 A. Light load conditions are a narrow circumstance in which a utility operating only 16 base load units would be forced to cut back output from the generation units to accommodate unscheduled QF energy purchases. These base load units might not 17 18 be able to increase the output rapidly enough if the QF resource output suddenly 19 drops off, which may result in the utility relying upon higher cost units to 20 maintain system reliability. FERC has confirmed that this exception only applies 21 during this unique light loading scenario and does not apply to curtail energy for 22 only general economic reasons.

⁴ Blue Marmot/301, Moyer/36 (PGE Response to Blue Marmot DR 103).

1 2	Q.	Does PGE claim that there would be curtailments because of light load conditions if it accepted the Blue Marmots' net output?
3	A.	No. PGE concedes that it does not anticipate this type of circumstance based on
4		current conditions. ⁵
5	Q.	Even if these circumstances applied, are they relevant to the Blue Marmots?
6	A.	No. A utility that has entered into a power purchase agreement or a LEO may not
7		curtail the QF's power during light load conditions. This exception only applies
8		when a QF does not have a long-term obligation and is instead delivering
9		unscheduled or non-firm energy. As explained by Mr. Talbott, the Blue Marmots
10		have LEOs with PGE.
	•	Is there an exception for a utility that has entered into contractual
11 12	Q.	commitments that limit its ability to accept the QF power?
	Q. A.	ı v
12		commitments that limit its ability to accept the QF power?
12 13		commitments that limit its ability to accept the QF power? No. If utilities could simply enter into contracts and eliminate their PURPA
121314		commitments that limit its ability to accept the QF power? No. If utilities could simply enter into contracts and eliminate their PURPA obligations, then utilities could easily circumvent their responsibility to purchase
12131415		commitments that limit its ability to accept the QF power? No. If utilities could simply enter into contracts and eliminate their PURPA obligations, then utilities could easily circumvent their responsibility to purchase and manage QF power. A utility cannot enter into a contract with terms and
1213141516		No. If utilities could simply enter into contracts and eliminate their PURPA obligations, then utilities could easily circumvent their responsibility to purchase and manage QF power. A utility cannot enter into a contract with terms and conditions that limit a QF from selling or delivering its power to the purchasing
12 13 14 15 16 17		commitments that limit its ability to accept the QF power? No. If utilities could simply enter into contracts and eliminate their PURPA obligations, then utilities could easily circumvent their responsibility to purchase and manage QF power. A utility cannot enter into a contract with terms and conditions that limit a QF from selling or delivering its power to the purchasing utility or limit the ability of the purchasing utility to purchase the net output of the

⁵ Blue Marmot/301, Moyer/37 (PGE Response to Blue Marmot DR 104).

purchase a QF's net output. PGE Merchant's existing agreements regarding

other contractual commitments cannot supersede their PURPA obligations.

power sales, participation in the Western Energy Imbalance Market ("EIM"), or

20

21

22

Q.	Is there an exception that allows a utility to refuse to purchase a QF's power because of transmission congestion or constraints?
A.	No. A QF cannot be given the choice between funding transmission upgrades or
	being unable to deliver its net output when there is transmission congestion or
	limited ATC. Even when there is no ATC on the purchasing utility's system to
	deliver the net output to load, the purchasing utility must accept and manage the
	power at the POD (or, in the case of an on-system QF, where the QF chooses to
	interconnect on the purchasing utility's system). The purchasing utility's options
	do not include refusing to sign a contract, abdicating its responsibility for
	managing the power, and requiring the QF to pay for firm transmission service or
	transmission upgrades on the utility's own system.
Q.	Does this mean that the Blue Marmots do not pay for any transmission costs?
A.	No. The Blue Marmots will pay for point-to-point transmission service from
	PacifiCorp to wheel their power to PGE, and are paying for the costs to
	interconnect to PacifiCorp's system at the POI. Thus, the Blue Marmots are
	already paying significant transmission and interconnection costs to deliver their
	power to PGE.
Q.	Why is PGE Merchant refusing to execute a contract with the Blue Marmots?
A.	PGE Merchant claims that the Blue Marmots have not made necessary
	transmission arrangements to deliver their net output to PGE's system.
	Specifically, PGE Merchant is refusing to agree to accept any power deliveries at
	the PACW.PGE POD. PGE Merchant appears to agree that the Blue Marmots
	Q. A.

have made arrangements to deliver the power to PGE's system. but PGE says 1 2 that it will not accept delivery at that the PACW.PGE POD because there is 3 insufficient ATC to deliver the OF power from the POD to PGE Merchant's load. 4 Q. What is PGE Merchant's justification for refusing to execute a PPA? 5 PGE Merchant has proposed that the Blue Marmots must either: 1) make 6 arrangements to deliver their power to PGE's system through another POD that is 7 not constrained; or 2) pay for required studies and upgrades to PGE's system at the PACW.PGE POD. Instead of taking responsibility for the power that is 8 9 delivered to its system, PGE Merchant has taken the position that the Blue 10 Marmots must deliver to a different POD or pay for transmission upgrades to 11 increase transmission capability on PGE's system between the PACW.PGE POD 12 and PGE's network load. Q. Please explain what PGE Merchant means by making arrangements to 13 deliver to another POD. 14 15 Α. As one of two alternatives offered by PGE Merchant to overcome the 16 transmission congestion PGE Merchant claims to exist on PGE's transmission 17 system, PGE Merchant would require the Blue Marmots to purchase transmission 18 on BPA's system to deliver at the PGE.BPA POD. This would require a "double 19 wheel" as the Blue Marmots would need to purchase point-to-point transmission 20 from both PacifiCorp and BPA. As explained in Mr. Talbott's testimony, this 21 would result in approximately \$14 million in additional costs for the Blue 22 Marmots over the term of the PPAs.

⁶ Blue Marmot/301, Moyer/26 (PGE Response to Blue Marmot DR 44).

E.g., UM 1829 PGE Answer to Blue Marmot V Complaint at ¶ 70-71.

- 1 Q. Please explain what PGE Merchant means by paying for transmission studies and upgrades at the PACW.PGE POD.
- 3 **A.** There is limited ATC at the PACW.PGE POD, primarily because PGE Merchant has reserved the transmission for itself, including for its participation in the EIM,
- 5 serving its own load, and other uses.
- 6 Q. How would the Blue Marmots pay for transmission studies and upgrades?
- 7 A. PGE Merchant has not made it clear how this would work. QFs, by nature, are 8 not transmission customers on the purchasing utility's system, so the specifics are 9 unknown. It appears that PGE Merchant is requiring that the Blue Marmots 10 become PGE transmission customers and make a transmission service request to 11 deliver from one location on PGE's transmission system (i.e., the PACW.PGE 12 POD) to another location on PGE's transmission system (i.e., PGE load). PGE 13 Transmission would then study whether any transmission upgrades are necessary 14 and how much they would cost. PGE Merchant would then require the Blue 15 Marmots to pay for any needed transmission upgrades and for transmission 16 service on PGE's system. While PGE Merchant does not appear willing to do so, 17 it is possible that PGE may reimburse the Blue Marmots for these paid upgrades 18 and reduce the transmission rates they pay to PGE Transmission (if any). Even if 19 PGE Transmission reimburses or credits the Blue Marmots for payment of these 20 transmission upgrades, the Blue Marmots would not be held harmless because 21 they would then have to pay PGE Transmission for use of PGE's transmission 22 system as long as they are selling power to PGE. This process is consistent with a 23 non-QF generator seeking point-to-point transmission service, however this is not 24 at all appropriate for QFs. Given that QFs are not required to purchase

1		transmission on the purchasing utility's system and the unprecedented nature of
2		PGE Merchant's actions, PGE Merchant may not even understand what it intends
3		to require the Blue Marmots to do.
4 5 6 7	Q.	Do you agree with PGE Merchant's proposal that the Blue Marmots must make arrangements to deliver to a different POD or that the Blue Marmots must pay for transmission studies and upgrades at the PACW.PGE POD to allow PGE Merchant to accept the power?
8	A.	No. As explained above, the Blue Marmots are only required to deliver their net
9		output to a POD of their choosing on the purchasing utility's transmission system,
10		which is the PACW.PGE POD. A QF cannot be given the choice of funding
11		transmission delivery upgrades, facing curtailment, or delivering at a POD of the
12		purchasing utility's choice. PGE Merchant is attempting to avoid its PURPA
13		obligation to purchase the Blue Marmots net output because it has failed or
14		refused to properly manage the QF power.
15 16	Q.	Instead of requiring the Blue Marmots to deliver to another POD or pay for network upgrades, what are PGE's options?
17	A.	After assuming its responsibility for the power, PGE Merchant must then decide
18		what it wants to use the net output for. PGE Merchant can make this decision
19		independently. After doing so, PGE Merchant can make the necessary
20		transmission arrangements to ensure that the Blue Marmots' net output is
21		transferred from the PACW.PGE POD to the location in which PGE elects to use
22		the power. Some of the specific options that PGE Merchant can take when
23		managing the power could include PGE Merchant: 1) completing transmission
24		upgrades that increase ATC and allow for PGE to accept the QF output at
25		PACW.PGE POD by obtaining <i>new</i> transmission rights; 2) obtaining transmission
26		service from a third-party transmission provider to wheel the power from the

PACW.PGE POD to another location of PGE's choosing; or 3) utilizing its own currently held *existing* transmission rights to accept and deliver the power, including reducing its own generation or market purchases to accommodate the QF power within those rights. There may be other options as well.

It is important to keep in mind that the Blue Marmots do not have the expertise and are not responsible for managing PGE Merchant's network resources or identifying all of PGE's options. PGE is a sophisticated, vertically integrated utility that serves its load with a variety of generation resources and market purchases transferred using both network and point-to-point transmission rights. If PGE makes an effort, I am confident that PGE can figure out a least cost and least risk approach to ensuring that the Blue Marmots' net output that is delivered to the PACW.PGE POD can be accepted and used to serve load.

- Q. Please explain what you mean by PGE Merchant can request and pay for transmission upgrades.
- **A.** Rather than the Blue Marmots making a transmission service request, PGE

 16 Merchant can make a transmission service request with PGE Transmission, pay

 17 for any studies associated with the request, and then pay for transmission

 18 upgrades to increase ATC at the PACW.PGE POD. These transmission upgrades

 19 could provide significant benefits to all of PGE Transmission's customers.
- 20 Q. Are you certain that there would be additional costs or required upgrades?
- **A.** No. PGE Merchant has not analyzed what the specific impacts would be if PGE decided to accept the Blue Marmots net output at the identified POD.⁸ The Blue

Blue Marmot/301, Moyer/21, 30, 38-41 (PGE Response to Blue Marmot DR 18, 53, 105-108).

Marmots sought to understand in the discovery process what actions PGE Merchant has taken to verify if there is any transmission available to PGE, and if 3 PGE Merchant has done anything other than look at PGE Transmission's Open Access Same Time Information System. PGE Merchant has not requested 4 5 transmission service from PGE Transmission to wheel the Blue Marmots' net 6 output from the PACW.PGE POD to load or another location. It is not known 7 what, if any, the costs and nature of the additional upgrades might be. We also do 8 not know if there are any strategies (e.g., re-dispatch) that could be put into place to mitigate the need for the upgrades in the first place.

Q. How would the costs of these network upgrades be recovered?

11 A. FERC's transmission policy requires transmission costs to generally be assessed 12 in a rolled-in rate, and not as an incremental basis for upgrades. Thus, PGE 13 Transmission function would construct the upgrades and then the costs would be 14 charged to all of PGE Transmission's customers, including PGE Merchant. This 15 process is clear and well accepted, unlike PGE Merchant's effective requirement 16 that a QF become a transmission customer of the purchasing utility and pay the 17 purchasing utility for both transmission upgrades and transmission rates. Blue 18 Marmot's preference is for PGE Merchant to work out a solution that avoids the 19 need for transmission upgrades altogether.

О. Does PGE Merchant have other options?

1

2

9

10

20

21 Yes. PGE could seek to convert its existing point-to-point transmission rights A. 22 between PACW and PGE to network integration transmission service rights by

⁹ Blue Marmot/301, Moyer/30 (PGE Response to Blue Marmot DR 53).

1		seeking to designate the Blue Marmots as network resources delivered at the
2		PACW.PGE POD. While I understand that PGE Merchant has committed to use
3		the point-to-point rights to facilitate imports (and exports) when participating in
4		the EIM, PGE Merchant cannot enter into contractual restrictions that have the
5		practicable effect of overriding its obligation to purchase from QFs. For example,
6		PGE could, during hours in which the Blue Marmots are generating, temporarily
7		reduce its imports of power at the PACW.PGE POD. Doing so would impact
8		PGE Merchant's operations only in situations where scheduled imports are
9		greater than the transfer capability remaining after the Blue Marmots' net output
10		is scheduled. Alternatively, PGE could temporarily adjust the amounts of
11		transmission included in the EIM (again, only as required when the Blue Marmots
12		are generating, and only in partial reductions relative to PGE's total transmission
13		rights on the path). Both options would allow PGE to accept the Blue Marmots'
14		net output while still allowing PGE Merchant to benefit from accessing these
15		markets.
16 17 18 19	Q.	Has PGE Merchant taken any actions to understand how it could manage its generation and transmission resources, including backing down its own generation or re-allocating its transmission to accept the Blue Marmots net output?
20	A.	Not that the Blue Marmots are aware of. Submitting a transmission service
21		request to PGE Transmission would be the first step and PGE does not appear to
22		have done this.

- 1 O. Are you aware of other utilities which have attempted to better manage their transmission assets to incorporate more QF power? 2 3 Α. Yes. FERC has allowed PacifiCorp to attempt to better manage its transmission 4 assets to accept QF power in transmission constrained areas by amending
- PacifiCorp's Network Operating Agreement. 10 5

7

18

A.

6 Q. What was the problem PacifiCorp was trying to solve?

PacifiCorp recognized that PURPA requires utilities to purchase QF power under 8 all circumstances, even when the QF has chosen to site in a constrained area. 9 PacifiCorp took the position that FERC does not allow the designation of a new 10 network resource until sufficient ATC is available, and PacifiCorp argued that 11 requirement put the utility in the position of having to construct network upgrades 12 to accommodate a QF using firm transmission service since the utility would not 13 have otherwise constructed those upgrades. Ultimately, FERC allowed 14 PacifiCorp to "live within its means" by managing new QFs and existing network 15 resources within its existing transmission rights, provided that the output of the 16 new QF was prioritized ahead of other non-QF generation and rights of other 17 transmission customers were not impacted.

Is this situation similar to what PGE is facing? Q.

19 Yes, it is very similar. The main difference is that PacifiCorp was facing a Α. 20 situation related to QF facilities on its system that were located in remote, 21 constrained areas and PGE's constraint is at a commonly used interface integrated 22 into its system. Both areas can be considered transmission constrained in terms of 23 a lack of long-term firm ATC.

¹⁰ PacifiCorp, 151 FERC ¶ 61,170 (2015).

1 While the details are complex, PacifiCorp recognized that it, as the 2 purchasing utility, was ultimately responsible for managing any QF power made 3 available to it, which could include paying for and constructing additional 4 transmission. PacifiCorp also recognized that it was to its customers' benefit to 5 identify creative solutions to integrate the QF output while also avoiding 6 transmission upgrades. In contrast, PGE is refusing to accept the Blue Marmots' 7 net output as a network resource because of insufficient ATC and is refusing to 8 take responsibility for the Blue Marmots' net output. Given that PGE Merchant 9 holds significant transmission rights between the PACW and PGE transmission 10 footprints, PGE's situation seems easier to manage because there are more options 11 to solve the alleged "problem." 12 Q. How did PacifiCorp propose to solve the issue of delivering a QF's net output from a constrained area on its own system to its load? 13 14 A. PacifiCorp proposed that its transmission function be able to grant additional 15 designated network resource status for its merchant function to enable firm 16 delivery from QFs even when there is no long-term firm ATC. Commensurately, 17 the PacifiCorp merchant function agreed to operate its portfolio of designated 18 network resources in the affected area within system reliability limits and curtail 19 QF power last, even if that is out of economic merit order. PacifiCorp would 20 curtail is own non-QF generation before curtailing QF power. 21 Q. Are you recommending that PGE Merchant adopt PacifiCorp's approach? 22 No. The point is not that PGE Merchant must take exactly the same approach as 23 PacifiCorp. Instead, I am referring to PacifiCorp's actions as an illustrative 24 example that there are practical approaches that a utility like PGE can take to

1 efficiently and effectively discharge its PURPA obligations. PGE Merchant has 2 taken the approach of simply refusing to purchase the Blue Marmots' net output rather than looking for creative solutions, which could include allowing PGE 3 4 Transmission to grant designated network resource status to enable firm delivery 5 from QFs, even when there is no long-term firm ATC. 6 While I do not agree with certain other aspects of PacifiCorp's 7 characterizations of its PURPA obligations, creative approaches like this would 8 be reasonable steps for PGE to take. The Commission should recognize that 9 FERC has allowed utilities some latitude to manage their QF power, and it is 10 reasonable to leave it up to PGE Merchant to properly manage its network 11 resources, including QF generation, because PGE Merchant is responsible for the 12 Blue Marmots' net output. 13 Q. Could PGE manage its EIM participation in a manner that accommodates 14 delivery of the Blue Marmots' output to PGE load? 15 A. Yes. PGE could choose to manage its participation in the EIM in such a way that 16 would allow it to accept the output from the Blue Marmots at the PACW.PGE 17 POD and deliver that output to PGE load. 18 Q. Please explain the options for PGE transfer of EIM energy with other EIM participants and how PGE could manage EIM participation while accepting 19 20 delivery from Blue Marmot.

Under PGE's tariff, PGE has established, and FERC has accepted, two methods

for enabling transfers between itself and other EIM Entities (such as PacifiCorp).

One method to enable EIM Transfers¹¹ is referred to as the "Interchange Rights

21

22

23

Α.

Under PGE's Tariff, EIM Transfers are defined as: "The transfer of real-time energy resulting from an EIM Dispatch Instruction: (1) between the PGE BAA and the CAISO BAA; (2) between the PGE BAA and an EIM Entity BAA; or (3)

Holder" methodology. A PGE Interchange Rights Holder is "a Transmission Customer who has informed the PGE EIM Entity that it is electing to make reserved firm transmission capacity available for EIM Transfers without compensation." This methodology allows a PGE Interchange Rights Holder to "donate" its reserved transmission capacity to the EIM. For instance, to facilitate EIM Transfers between PacifiCorp and the CAISO, PacifiCorp Merchant donates some of its transmission rights on the California-Oregon Intertie. PGE indicated it plans to use the Interchange Rights Holder methodology for EIM Transfers on two paths that will enable energy exchanges between PGE and the CAISO. 13

Notably, PGE did not indicate that it planned to use the PGE Interchange Rights Holder method for EIM Transfer to and from PacifiCorp. Instead, for the transfer of EIM energy to and from PacifiCorp West, PGE's FERC filing stated that PGE will utilize the ATC method for EIM Transfers at the direct interface between the PGE Balancing Authority Area ("BAA") and the PacifiCorp West BAA. The ATC method allows for EIM Transfers based on the ATC that PGE calculates to exist prior to the operating hour. The ATC calculation for EIM Transfers takes place at approximately 40 minutes prior to the operating hour and takes into account all scheduled uses of the relevant path that have been

between the CAISO BAA and an EIM Entity BAA using transmission capacity available in the EIM."

14 Id.

Portland General Electric, *Pro Forma Open Access Transmission* Tariff; updated May 1, 2017 at 1.78.

Portland General Electric Company, "Amendments to the Portland General Electric Company Open Access Transmission Tariff to Facilitate Energy into the Energy Imbalance Market," FERC Docket No. ER17-1075-000, filed March 1, 2017, at II.E.

1		submitted. Note that 40 minutes prior to the operating hour will occur after the
2		Blue Marmots have scheduled their output, giving PGE the information it would
3		need to release any unused transmission rights into the EIM.
4		The remaining ATC on the path is then communicated to the EIM operator
5		(the CAISO) and the EIM is optimized based on the transmission capacity that the
6		EIM Entity (in this case PGE) has indicated to be available. Under this method,
7		there is no requirement for transmission service to be donated by a PGE
8		Interchange Rights Holder and PGE Merchant has no obligation to hold long-term
9		firm transmission capacity on the path to enable its EIM participation. Therefore,
10		one option available to PGE is to schedule the anticipated output from the Blue
11		Marmot on the PACW.PGE to PGE path along with other uses of the path, and
12		then utilize the remaining transmission capacity on the path to enable EIM
13		Transfers, consistent with the ATC method for EIM Transfers.
14 15	Q.	Would this approach be consistent with the approaches of other EIM Entities?
16	A.	Yes. Most other EIM Entities participate in the EIM primarily using the ATC
17		method. To the best of my knowledge, these EIM Entities continue to enable
18		other uses of their transmission system prior to the EIM time horizon and no other
19		EIM Entity's merchant function has procured new transmission capacity that is
20		purely dedicated to enabling EIM Transfers.
21 22 23	Q.	Is there any reason PGE couldn't manage its EIM participation in the manner described above, which would allow delivery of the Blue Marmots' output to PGE load?
24	A.	Not that I am aware of. In fact, the method of accepting Blue Marmot's output
25		and conducting EIM Transfers is consistent with the manner in which PGE told

1		FERC it would be effectuating EIM Transfers between its own BAA and the
2		PACW BAA. When PGE sought, and subsequently received, Market Based Rate
3		Authority in the EIM, PGE represented to FERC that its merchant function would
4		provide at least 200 megawatts ("MW") of transmission to the EIM in all
5		intervals. ¹⁵ Therefore, should PGE choose this option for accepting the Blue
6		Marmots' net output, PGE would likely need to make a Market Based Rate
7		Authority change in status filing at FERC. The change in status filing, and any
8		resulting decisions, should not prevent PGE from managing its EIM participation
9		in a manner that allows for delivery of the Blue Marmots output.
10 11	Q.	Are you recommending that PGE manage its EIM participation to allow delivery of the Blue Marmots' output to PGE load?
12	A.	No. I am not familiar enough with all of the details of PGE's EIM participation
13		and system operations to know whether this is the appropriate action for PGE to
14		take to accept the Blue Marmots' net output. I am simply pointing out that PGE
15		has a variety of options available to accept the Blue Marmots' net output and that,
16		should PGE choose this option, it would be consistent with PGE's tariff, its
17		representations to FERC in filing for approval of its EIM tariff modifications, and
18		with the approaches of other EIM Entities.
19	III.	AVOIDED COST RATES
20	Q.	Please summarize this portion of your testimony.
21	A.	The avoided cost rate at the time a QF enters into a contract or LEO cannot
22		change or be altered by the utility. Since the Blue Marmots have legally

Blue Marmot/301, Moyer/1-20 (PGE Response to Blue Marmot DR 2, Appendix A).

1 enforceable obligations at the rates that were in effect in April 2017, PGE cannot 2 now change the Blue Marmots avoided cost rate. This change to the Blue 3 Marmots' avoided cost rates cannot be in the form of an actual change to the 4 contract price, nor can it be an effectual change resulting from incremental 5 transmission costs. 6 What is your understanding of how PGE's avoided cost rates are set? Q. 7 While I am generally familiar with and have reviewed PGE's avoided cost rate A. 8 workpapers, I am not an expert on all the details regarding the calculation of 9 Oregon avoided cost rates. There are a variety of different ways in which avoided cost rates are calculated around the country, ¹⁶ and Oregon uses a form of the 10 "proxy" methodology for OFs under the size threshold for standard rates. 17 At the 11 12 time the Blue Marmots obtained their LEOs, the standard rate eligibility cap was 13 10 MW for solar generation selling power to PGE. These standard rates are 14 intended to reflect the utility's full avoided costs, but are administratively 15 determined by the OPUC. The standard rates are adjusted to be based on the 16 generic resource characteristics of each QF technology type, which means that a 17 solar OF's rates reflect the different peak capacity credit versus a baseload OF 18 with a different generation profile. Thus, there are generic resource type

Carolyn Elefant, REVIVING PURPA'S PURPOSE: The Limits of Existing State Avoided Cost Ratemaking Methodologies In Supporting Alternative Energy Development and A Proposed Path for Reform, First Impression – Last resort (Oct. 2011), http://lawofficesofcarolynelefant.com/reports-publications/. (explaining basic methodologies for calculating avoided cost rates).

Re OPUC Investigation Into Qualifying Facility Contracting and Pricing, Docket No. UM 1610, Order No. 14-058 at 8-14 (Feb. 24, 2014).

1		adjustments, but there are no project specific adjustments to the avoided cost rate
2		calculation.
3 4	Q.	Can PGE adjust an off-system QF's avoided cost rates to reflect the costs of transmission on its system?
5	A.	While I am not an attorney, my understanding is that PGE cannot. As mentioned
6		above, FERC regulations provide that off-system QFs like the Blue Marmots can
7		wheel their power to a purchasing utility like PGE, and the purchasing utility must
8		purchase the net output as if the QF were supplying the net output directly.
9		FERC's regulations also state that the rate "shall not include any charges for
10		transmission." ¹⁸ This is consistent with the discussion above that the purchasing
11		utility is responsible for accepting and managing the power that is delivered to its
12		system. Therefore, the rate paid to the off-system QF cannot directly or indirectly
13		include any transmission charges.
14 15	Q.	Is PGE seeking to impose a transmission charge on the Blue Marmots and thereby lower the Blue Marmots' <i>effective</i> avoided cost rates?
		thereby lower the blue Marmots effective avoided cost rates.
16	A.	Yes. PGE is not explicitly seeking to change the specific rate that is paid to the
16 17	A.	
	A.	Yes. PGE is not explicitly seeking to change the specific rate that is paid to the
17	A.	Yes. PGE is not explicitly seeking to change the specific rate that is paid to the Blue Marmots; however, PGE is requiring that before it will accept the Blue
17 18	A.	Yes. PGE is not explicitly seeking to change the specific rate that is paid to the Blue Marmots; however, PGE is requiring that before it will accept the Blue Marmots' net output, they must purchase transmission from PGE or another third-
17 18 19	A. Q.	Yes. PGE is not explicitly seeking to change the specific rate that is paid to the Blue Marmots; however, PGE is requiring that before it will accept the Blue Marmots' net output, they must purchase transmission from PGE or another third-party, or fund transmission upgrades. This is a de facto transmission charge
17 18 19 20 21		Yes. PGE is not explicitly seeking to change the specific rate that is paid to the Blue Marmots; however, PGE is requiring that before it will accept the Blue Marmots' net output, they must purchase transmission from PGE or another third-party, or fund transmission upgrades. This is a de facto transmission charge which ultimately lowers the avoided cost rate paid to the Blue Marmots. Is PGE allowed to change the avoided cost rate after the QF has entered into
17 18 19 20 21 22	Q.	Yes. PGE is not explicitly seeking to change the specific rate that is paid to the Blue Marmots; however, PGE is requiring that before it will accept the Blue Marmots' net output, they must purchase transmission from PGE or another third-party, or fund transmission upgrades. This is a de facto transmission charge which ultimately lowers the avoided cost rate paid to the Blue Marmots. Is PGE allowed to change the avoided cost rate after the QF has entered into a contract or obtained a legally enforceable obligation?

¹⁸ 18 CFR 292.303(d).

made prospectively and prior to establishing a LEO. Thus, even if PGE could in theory impose a transmission charge or otherwise reduce the avoided cost rate paid to the Blue Marmots, this would need to be done prior to when the LEO occurred, which was the date that the Blue Marmots executed the PPAs and returned them unaltered to PGE. I have been informed by counsel that PGE or the OPUC cannot unilaterally adjust rates in a fixed price contract, or otherwise adjust the compensation paid to the QF under the contract because PURPA prohibits utilities and regulators from exercising any kind of post-contractual price modification. In the context of this case, because the Blue Marmots have executed contracts with PGE that establishes a LEO under a specific avoided cost rate, no other costs associated with transmission upgrades on PGE's system can be allocated to the Blue Marmots.

13 IV. <u>DISCRIMINATION</u>

1

2

3

4

5

6

7

8

9

10

11

12

- 14 Q. Please summarize this portion of your testimony.
- 15 A. PGE is discriminating against the Blue Marmots because it has refused to execute 16 the Blue Marmots' PPAs while executing contracts with other QFs that are 17 planning to deliver their net output at the PACW.PGE POD. PGE has also 18 discriminated in favor of itself over the Blue Marmots by claiming that there is no 19 ATC to accept their power, but then obtaining ATC that becomes available at the 20 PACW.PGE POD for other non-OF purposes. This is troubling because PGE 21 appears to be procuring transmission solely for its own purposes when it should 22 be seeking to arrange for transmission service to be used to deliver power from 23 QFs that have LEOs.

1 Q. Is PGE allowed to discriminate against similarly situated QFs?

2 **A.** No. Again, while I am not a lawyer, my understanding is that PGE cannot unduly discriminate between different QFs.

4 Q. Is PGE discriminating against the Blue Marmots?

5 A. Yes, PGE is discriminating or treating the Blue Marmots differently from other 6 similarly situated QFs. PGE has entered into at least three off-system QF contracts that will deliver to the PACW.PGE POD. 19 These include the Airport 7 8 Solar PPA, which is also planned to interconnect to PacifiCorp and deliver its net 9 output to PGE via PacifiCorp's system. The Airport Solar PPA was executed a 10 couple weeks before PGE informed the Blue Marmots that it would not execute 11 PPAs but after PGE had provided executable PPAs and after Blue Marmot had executed these PPAs.²⁰ 12

Q. What should PGE have done?

13

14

15

16

17

18

19

20

A. PGE should have executed the Blue Marmots' contracts, just as it had already done for the other off-system QFs delivering at the PACW.PGE POD. If PGE has any concerns regarding the specific transmission arrangements, then it should not use those as an excuse not to execute these contracts and should have handled all of the tendered PPAs similarly. I have been informed by counsel that, once PGE issues executable PPAs, it is required to honor those PPAs, and is barred from raising any new concerns. Thus, PGE should have counter-signed the PPAs

Blue Marmot/301, Moyer/25 (PGE Response to Blue Marmot DR 28).

Re PGE Information Filing of Qualifying Facility Contracts or Summaries per OAR 860-029-0020(1), Docket No. RE 143, PGE's Summary of Qualified Facility Agreements (June 21, 2017) (PGE summary of Airport Solar PPA with an execution date of April 3, 2017) Available at:

http://edocs.puc.state.or.us/efdocs/HAQ/re143haq165856.pdf

1		signed by Blue Marmot and started making arrangements to manage the QF
2		power.
3 4 5	Q.	Are you taking the position that PGE should now refuse to accept the net output of the other off-system QFs that it has already agreed to accept deliveries from at the PACW.PGE POD?
6	A.	No. PGE should not remedy its discriminatory treatment against the Blue
7		Marmots by refusing to accept the net output of any off-system QFs that have
8		entered into contracts or otherwise have established legally enforceable
9		obligations. ²¹ Instead, PGE should accept responsibility for managing at least the
10		power of all the QFs that have entered into contracts or obtained legally
11		enforceable obligations.
12 13	Q.	Is PGE treating the Blue Marmots as QFs that have contracts or legally enforceable obligations?
	Q.	
13		enforceable obligations?
13 14		enforceable obligations? No. PGE has vaguely stated that "All QFs that have requested PPAs from PGE
131415		enforceable obligations? No. PGE has vaguely stated that "All QFs that have requested PPAs from PGE and that have requested to deliver at PACW.PGE will be given the same options
13141516		enforceable obligations? No. PGE has vaguely stated that "All QFs that have requested PPAs from PGE and that have requested to deliver at PACW.PGE will be given the same options as Blue Marmot." This statement only applies to QF requests, and not to QFs
1314151617		enforceable obligations? No. PGE has vaguely stated that "All QFs that have requested PPAs from PGE and that have requested to deliver at PACW.PGE will be given the same options as Blue Marmot." This statement only applies to QF requests, and not to QFs that have already entered into contracts. Thus, PGE appears to be treating Blue
131415161718		enforceable obligations? No. PGE has vaguely stated that "All QFs that have requested PPAs from PGE and that have requested to deliver at PACW.PGE will be given the same options as Blue Marmot." This statement only applies to QF requests, and not to QFs that have already entered into contracts. Thus, PGE appears to be treating Blue Marmot as a QF that has merely requested a PPA from PGE, rather than as a QF
13 14 15 16 17 18		enforceable obligations? No. PGE has vaguely stated that "All QFs that have requested PPAs from PGE and that have requested to deliver at PACW.PGE will be given the same options as Blue Marmot." This statement only applies to QF requests, and not to QFs that have already entered into contracts. Thus, PGE appears to be treating Blue Marmot as a QF that has merely requested a PPA from PGE, rather than as a QF

As noted above, PGE is obligated to purchase the net output of all off-system QFs and manage their power regardless of whether they have entered into a contract or not. There are additional reasons why PGE cannot refuse to purchase the net output of QFs like the Blue Marmots which have legally enforceable obligations or contracts.

Blue Marmot/301, Moyer/23 (PGE Response to Blue Marmot DR 23).

Q. Do we know what PGE is planning to do regarding QFs that have entered into fully executed contracts with PGE?
 A. No. The Blue Marmots sought to obtain this information in the discovery

process, and PGE has not determined how to proceed.²³ For example, the Blue 4 5 Marmots sought to obtain PGE's position on what it would do with any additional ATC that is made available at the PACW.PGE POD, whether PGE would use that 6 7 ATC for other off-system QFs, and whether there would be any priority between off-system QFs that are requesting to deliver at the PACW.PGE POD.²⁴ PGE 8 9 claims that it "is in the process of developing a policy to address" these 10 circumstances, that it has not yet made a determination about whether it can even accept deliveries, or how deliveries will be handled.²⁵ 11

Q. What does PGE mean by stating that it "is reviewing off-system QFs that have entered PPAs and has not made a determination about whether it can accept deliveries from each of them at this time" or that "PGE is evaluating how deliveries anticipated to be made from [the projects that have executed contracts] to the PACW.PGE POD will be handled"?

17

18

19

20

21

22

A. We do not know. PGE's statement is inconsistent with its other positions in this case. On one hand, PGE claims that it cannot accept any power deliveries at the PACW.PGE POD because of insufficient ATC. However, on the other hand, PGE has not made a determination about how it will handle deliveries or whether it can even accept deliveries at the same location that has insufficient ATC from those QFs that have already entered into contracts.

Blue Marmot/301, Moyer/22-24 (PGE Response to Blue Marmot DR 22-24).

Blue Marmot/301, Moyer/24 (PGE Response to Blue Marmot DR 24).

Blue Marmot/301, Moyer/23-24, 25, 34-35 (PGE Response to Blue Marmot DR 23-24, 28, 91, 92).

1		There are over 67 MW of off-system QFs that have already entered into
2		contracts with PGE to deliver at the PACW.PGE POD, and PGE appears to be
3		holding open the door to accept some or all of their net output at this POD. ²⁶ PGE
4		also appears to be taking the position that the time a QF enters into a contract
5		somehow impacts whether PGE has to accept delivery at the PACW.PGE POD.
6 7	Q.	Separate from its obligations to individual QFs, is PGE discriminating against the Blue Marmots in favor of other transmission uses?
8	A.	It appears so. Additional ATC became available after PGE informed the Blue
9		Marmots that PGE would not purchase their net output due to limited ATC. ²⁷
10		PGE could have reserved or obtained this to accept at least a portion of the Blue
11		Marmots' net output or otherwise meet its PURPA obligations, but PGE elected
12		to reserve this for itself as point-to-point transmission. PGE also could have
13		informed the Blue Marmots that this ATC had become available. Instead PGE
14		appeared to act as if it had no knowledge of its obligations to accept the Blue
15		Marmots' output on that same transmission path.
16	V.	CONCLUSION
17	Q.	Does this conclude your testimony?
18	A.	Yes.

The Airport Solar QF (47.25 MW), OM Power (10 MW), and Obsidian Renewables (10 MW).

Blue Marmot/301, Moyer/29-32 (PGE Response to Blue Marmot DR 52-55).

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM 1829, UM 1830, UM 1831, UM 1832, UM 1833

BLUE MARMOT V LLC (UM 1829))
BLUE MARMOT VI LLC (UM 1830))
BLUE MARMOT VII LLC (UM 1831))
BLUE MARMOT VIII LLC (UM 1832))
BLUE MARMOT IX LLC (UM 1833))
Complainants)
VS.)
PORTLAND GENERAL ELECTRIC)
COMPANY)
Defendant)
Pursuant to ORS 756.500.)
)

EXHIBIT BLUE MARMOT/301 PGE DATA RESPONSES

October 13, 2017

July 7, 2017

TO: Irion Sanger

Leslie Freiman Will Talbott

FROM: Karla Wenzel

Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC UM 1829 PGE Response to Blue Marmot Data Request No. 2 Dated June 23, 2017

Request:

2. Please provide either a copy of PGE's market based rates filing with FERC (that describes the transmission arrangements that will allow PGE to participate in the EIM) or a current draft of that filing.

Response:

Please see Attachment A, PGE's Notice of Change in Status for ER10-2249, which informs FERC of a change in the facts and circumstances that the Commission relied upon in granting PGE market based rate authority.



1050 Thomas Jefferson Street, NW Seventh Floor Washington, DC 20007 (202) 298-1800 Phone (202) 338-2416 Fax

Justin P. Moeller (202) 298-1847 jpx@vnf.com

June 16, 2017

Kimberly D. Bose Secretary Federal Energy Regulatory Commission 888 First Street, NE Washington, DC 20426

> Re: <u>Portland General Electric Company</u>, Docket No. ER10-2249-____ Notice of Change in Status

Dear Secretary Bose:

Portland General Electric Company ("PGE") hereby submits for filing this notice of change in status in compliance with the requirements set forth in section 35.42 of the regulations of the Federal Energy Regulatory Commission ("Commission" or "FERC").¹

The instant notice is filed to satisfy Commission directives to prospective participants in the Energy Imbalance Market ("EIM") with market-based rate ("MBR") authorization. The Commission has indicated that the EIM constitutes "a new relevant geographic market for market power purposes," and that commencing participation therein represents a change from the facts and circumstances the Commission relied upon in granting a seller MBR authority. PGE anticipates commencing financially binding EIM operations on October 1, 2017, at which point the EIM will consist of seven balancing authority areas ("BAAs").3

¹ 18 C.F.R. § 35.42 (2016).

² PacifiCorp, 147 FERC ¶ 61,227, at P 206, reh'g denied, 149 FERC ¶ 61,057 (2014), reh'g denied, 150 FERC ¶ 61,084 (2015).

The seven BAAs making up the EIM market are those of: Arizona Public Service Company ("APS"), California Independent System Operator Corporation ("CAISO"), Nevada Power Company and Sierra Pacific Power Company (together, "NV Energy"), Puget Sound Energy, Inc. ("PSE"), PacifiCorp, which operates the PacifiCorp-East and PacifiCorp-West BAAs, and PGE (collectively, the "EIM Footprint"). PGE, PSE, APS, NV Energy, and PacifiCorp are each an "EIM Entity" and together the "EIM Entities."

This change in status includes a market power analysis of PGE's participation in the new relevant geographic market comprised of the 7-BAA EIM Footprint. The attached Affidavit of Matthew E. Arenchild of Navigant Consulting, Inc. ("Navigant") with related exhibits⁴ examines PGE's participation in the EIM Footprint utilizing the Commission's indicative horizontal market power screens, as modified to conform with the Commission's guidance to PacifiCorp, NV Energy, PSE, and APS, and to reflect the particular circumstances of the EIM. Mr. Arenchild's analysis demonstrates that PGE passes the indicative screens and therefore lacks horizontal market power in the 7-BAA EIM Footprint. The ensuing discussion also affirms that PGE continues to lack vertical market power.

In addition to analyzing market power in the broader EIM Footprint, the Commission has previously held that EIM participants must also take into account whether the existence of frequently binding transmission constraints create a separate relevant geographic submarket that should be studied.⁵ An EIM participant is

permitted to demonstrate that there are no frequently binding transmission constraints that would limit imports into its home [BAA] (or the [BAA] where its generation is located) such that the home [BAA] should not be deemed to be an EIM submarket itself, or to be within an EIM submarket.⁶

The Commission has explained that, "[h]aving made such a demonstration, there would be no need for a seller to submit a separate market power analysis for its home [BAA]."⁷ For example, PSE demonstrated a lack of frequently binding constraints for its home BAA and was authorized by the Commission to transact in the EIM at market-based rates based on a demonstrated lack of market power in the overall EIM Footprint.⁸

Consistent with this guidance, PGE has attached to this filing letter affidavits and accompanying exhibits from Mr. Arenchild and from Zachary A. Gill Sanford, also of Navigant, which collectively demonstrate that (i) the 200 MW of firm transmission on the PacifiCorp West ("PACW")-to-PGE path that will be committed for in-bound EIM transfers by PGE's merchant function ("PGE Merchant") experienced no instances of transmission congestion (firm or non-firm) during the December 2014 to November 2015 MBR study period ("Study Period"); and (ii) based on the accuracy of historical hourahead load and variable generation forecasts within the PGE BAA during the Study Period, the demand for imbalance energy in the PGE BAA is likely to average 45.10 MW

As discussed further below, PGE requests privileged treatment for components of the Workpapers supporting Mr. Arenchild's analysis.

Nev. Power Co., 151 FERC ¶ 61,131, at P 201 & n.384, order on reh'g and clarification, 153 FERC ¶ 61,306 (2015).

Ariz. Pub. Service Co., 156 FERC ¶ 61,148, at P 28 (2016).

⁷

Puget Sound Energy, Inc., 156 FERC ¶ 61,242, at P 23 (2016).

and fall within a range of plus/minus 117 MW during 95% of all 15-minute intervals. Together, these demonstrations indicate that sufficient firm, unconstrained transmission will be available to ensure a competitive supply of imported generation to meet the demand for imbalance energy in the PGE BAA. Accordingly, the PGE BAA should not be deemed a submarket within the EIM Footprint requiring a separate market power analysis.

Based on the demonstrations made herein, PGE requests that the Commission issue an order prior to October 1, 2017 accepting this notice of change in status and authorizing PGE to transact in the EIM at market-based rates.

I. BACKGROUND

A. PGE Corporate Information

PGE is a regulated, vertically integrated electric utility located in the Western Electricity Coordinating Council. It provides electric service to over 840,000 residential, commercial and industrial customers in Oregon. PGE owns generation, transmission, and distribution facilities for service to wholesale and retail customers, and it buys and sells power in the Western energy markets. PGE also owns a 79.5% interest in the 17-mile Kelso-Beaver interstate gas pipeline. PGE is subject to the regulatory authority of the Oregon Public Utility Commission for its Oregon utility operations, and to the jurisdiction of FERC for the sale of electricity and transmission services in interstate commerce and for interstate natural gas transportation provided through its Kelso-Beaver pipeline.

PGE's affiliates, none of which own or control any electric generation or transmission facilities or has MBR authority, are:

- 1. Salmon Springs Hospitality Group, Inc., formed on April 9, 1998 (whose business is providing catering services to the Portland World Trade Center ("WTC") activities and does some catering outside of WTC as well);
- 2. 121 SW Salmon Street Corporation, formed April 24, 1975 (whose business is the collection of rents from PGE for the WTC lease payments on 121 SW Salmon Street in Portland, and to make payments to the lease owner);
- 3. World Trade Center Northwest Corporation, formed February 24, 1988 (whose business is the holding of the World Trade Center franchise); and

As discussed further below, Mr. Arenchild also considers the possibility that two PGE wind resources will be pseudo-tied into the PGE BAA during the first year of PGE EIM operations. Mr. Arenchild demonstrates that even with these resources, the demand for incremental imbalance energy in the BAA is expected to exceed 200 MW during just 1.6% of market intervals.

4. Portland General Gas Supply Company, formed on March 31, 2016 (currently inactive, but whose business will be to own gas reserves to provide a long-term hedge for PGE generation facilities' gas requirements).

B. PGE's Market Based Rate Authority

PGE is authorized by the Commission to sell energy and capacity at market based rates in all U.S. markets¹⁰ except for the PGE BAA.¹¹ After placing into service the 440 MW gas-fired Carty Generating Station on June 30, 2016, PGE adopted changes to its MBR tariff providing that PGE will not make any market-based rate sales within the PGE BAA.¹² PGE also has authorization to sell the following ancillary services at market-based rates: regulation service, reactive supply and voltage control service, spinning reserve service, and non-spinning reserve service to CAISO and to others that are self-supplying ancillary services to CAISO.¹³

More recently, PGE filed proposed amendments to its MBR tariff to accommodate participation in the EIM in two different circumstances: (i) the Commission has not yet acted on this change in status filing or has acted and determined that PGE lacks MBR authority in the EIM; or (ii) the Commission has accepted this change in status filing and authorized PGE to transact in the EIM at market-based rates. ¹⁴ In the former circumstance, the proposed MBR tariff amendments would limit PGE's bids into the EIM to the Default Energy Bid ("DEB") calculated in accordance with the Variable Cost or Negotiated Rate Options provided in the CAISO Tariff. The proposed amendments are currently pending Commission review and acceptance in Docket No. ER17-1693-000.

C. The EIM

The EIM emerged from the efforts of Western utility regulators earlier this decade to explore the benefits of a multi-state market for imbalance energy. In response to that initiative, CAISO proposed to utilize its existing market platform to integrate BAAs outside California with the CAISO BAA for purposes of supplying imbalance energy under a single intra-hour economic dispatch model. Specifically, the EIM enables entities with BAAs outside of CAISO to voluntarily take part in the imbalance energy portion of the CAISO locational marginal price ("LMP")-based real-time electricity market alongside participants from within the CAISO BAA.

Portland Gen. Elec. Co., Letter Order, Docket Nos. ER98-1643-014, et al. (issued June 22, 2011).

¹¹ Portland Gen. Elec. Co., Letter Order, Docket Nos. ER10-2249-006, et al. (issued Dec. 1, 2016).

¹² *Id*.

¹³ Portland Gen. Elec. Co., Letter Order, Docket No. ER99-1263-000 (issued Mar. 8, 1999).

¹⁴ *Portland Gen. Elec. Co.*, Amendments to the Portland General Electric Company Market-Based Rate Tariff to Facilitate EIM Participation, Docket No. ER17-1693-000 (filed May 26, 2017).

The EIM is an organized market, administered by CAISO, with well-documented market monitoring and mitigation procedures that have been found just and reasonable by the Commission. The EIM's monitoring, mitigation, and design features ensure a competitive supply of imbalance energy for market participants.

1. Local Market Power Mitigation within Each EIM BAA

CAISO applies real-time local market power mitigation when there is a noncompetitive, binding constraint within an EIM BAA using the local market power mitigation measures described in Section 39.7 of the CAISO Tariff. ¹⁵ Thirty-seven minutes in advance of each 15-minute market interval, CAISO performs an analysis to identify when congestion is likely to occur on specific constraints within an EIM BAA. Within each 15-minute interval, CAISO now conducts an additional mitigation analysis for each of the constituent 5-minute intervals. 16 For each constraint that is projected to be binding during the interval, CAISO performs a three pivotal supplier test to determine if the supply available to relieve the binding constraint is structurally competitive or noncompetitive. 17 If there is sufficient supply available to effectively alleviate the constraint after eliminating the three largest suppliers, the constraint is deemed to be structurally competitive and no mitigation is imposed. If the supply from one or more of the three largest suppliers is necessary to alleviate the constraint, economic bids from participating resources that are effective at alleviating the constraint will be subject to bid mitigation at the higher of: (i) a competitive LMP calculated by the market software (which excludes congestion from noncompetitive constraints); and (ii) the DEB of the participating resource, which reflects the cost of an incremental unit of production from the resource, plus a 10% adder. The Commission accepted as just and reasonable CAISO's extension of local market power mitigation in the CAISO energy market to the EIM in the CAISO EIM Order. 18

¹⁵ See California Independent System Operator Corporation, Fifth Replacement FERC Electric Tariff § 29.39 ("CAISO Tariff"). See also Cal. Indep. Sys. Operator Corp., 147 FERC ¶ 61,231, at P 217 ("CAISO EIM Order"), order on reh'g and clarification, 149 FERC ¶ 61,058 (2014), petition for review dismissed, Cal. Indep. Sys. Operator Corp. v. FERC, No. 14-1291 (D.C. Cir. Jan. 16, 2015).

¹⁶ See Cal. Indep. Sys. Operator Corp., 157 FERC ¶ 61,091 (2016) (accepting CAISO's proposed 5-minute mitigation measures); Cal. Indep. Sys. Operator Corp., 159 FERC ¶ 62,166 (2017) (extending implementation date of 5-minute mitigation measures no later than May 31, 2017).

The process used to determine if a path is competitive or not is the dynamic competitive path assessment. For every transmission constraint that is binding in this pre-market run, CAISO calculates a residual supplier index ("RSI") based on a three pivotal supplier test. This test is based on the ratio of supply of potential counter flow (excluding the three largest suppliers) compared to the demand for counter flow needed to relieve congestion on the constraint. Resources with negative shift factors relative to the congested constraint are able to provide counter flow that alleviates congestion. The demand for counter flow is calculated by summing up the level at which resources able to provide counter flow were dispatched in the pre-market run multiplied by each resource's shift factor. The RSI test determines if the three largest suppliers are pivotal for a constraint in terms of counter flow. If they are pivotal, meaning the residual supply of potential counter flow without these three suppliers cannot meet the demand for counter flow, the constraint is deemed noncompetitive.

¹⁸ CAISO EIM Order at P 217.

2. Structural Market Power Mitigation on Interties between the EIM BAAs

In addition to mitigating local market power on noncompetitive constraints within the PGE BAA and other EIM BAAs, CAISO will also apply the same local market power mitigation measures contained in Section 39.7 of its tariff when the interties connecting the EIM BAAs become constrained. CAISO currently applies market power mitigation on the external interties of EIM when constraints bind with respect to incoming transfers of imbalance energy, and such congestion is noncompetitive due to a high concentration of supply within the BAA. In such circumstances, CAISO will mitigate bids from participating resources that can relieve congestion on the intertie if the bid from the resource exceeds both (i) a competitive LMP calculated by the market software (which excludes congestion from noncompetitive constraints); and (ii) the DEB of the participating resource. As explained by CAISO's Director of Market Monitoring Eric W. Hildebrandt:

For instance, assume a unit within an EIM BAA has a marginal cost of \$30/MW and a DEB of \$33/MW after application of the 10 percent adder. Further assume that market power mitigation procedures are triggered by congestion into this EIM BAA during a 15-minute interval on EIM transfer constraints that is noncompetitive due to a high concentration of ownership of supply resources in this EIM BAA. During this interval, the competitive LMP for this 15-minute interval used in mitigation is \$40/MW. If the unit is bid into the EIM market at a price up to \$40/MW, the bid would not be lowered. If the unit was bid at a higher price, such as \$60/MW, the bid would be capped at the higher of (1) the competitive LMP (\$40/MW) or (2) the unit's DEB (\$33/MW). Thus, if the unit had a higher marginal cost of \$50/MW, for example, the unit's bid would be reduced to its DEB of \$55/MW (\$50/MW + 10 percent adder).²¹

In this way, binding constraints that preclude EIM transfers into an EIM Entity's BAA will be enforced by CAISO with bid mitigation where the supply of imbalance energy internal to the islanded BAA is noncompetitive.

Section 29.39 of the CAISO Tariff requires CAISO to conduct a competitive path assessment for each EIM Entity BAA, perform an LMP decomposition identifying any resources in the EIM which may have local market power due to a transmission constraint, and mitigate any such resources using their DEBs. In the case of both PacifiCorp BAAs²² and the NV Energy BAA,²³ CAISO determined, following a

²¹ *Cal. Indep. Sys. Operator Corp.*, ISO Tariff Amendments to the Energy Imbalance Market, Attachment D – Declaration of Eric W. Hildebrandt on Behalf of the California Independent System Operator Corporation, ¶ 30, Docket No. ER14-2484-000 (filed July 23, 2014).

¹⁹ See CAISO Tariff § 29.39(d).

²⁰ Id

²² See Cal. Indep. Sys. Operator Corp., 149 FERC ¶ 61,058, at PP 76, 81 (2014).

structural competitive assessment (then required by FERC), that it should apply local market power mitigation measures under Section 39.7 of the CAISO Tariff when constraints bind on the interties. As part of the EIM Year One Enhancements, Phase 2, CAISO proposed and FERC accepted tariff provisions that apply local market power mitigation to all interties within the EIM, including those that interconnect the PSE BAA with the rest of the market, without the need for a structural competitiveness assessment or FERC filing.²⁴ Thus, PGE's intertie with the PACW BAA will be tested for competitiveness any time it is binding, and any supply found to be noncompetitive will be mitigated.

D. Open Access Transmission Tariff Changes to Support EIM Operations

On March 1, 2017, PGE filed its proposed Open Access Transmission Tariff ("OATT") revisions to enable EIM participation as of October 1, 2017.²⁵ PGE's OATT revisions were accepted by the Commission on April 19, 2017.²⁶ PGE's OATT revisions include a new OATT attachment dedicated to defining the rights and responsibilities of PGE and its OATT customers with respect to the EIM. Generation resources that are physically located within the PGE BAA or pseudo-tied into the PGE BAA are eligible to register as Participating Resources in the EIM and submit economic bids to sell imbalance energy to the market.

E. Transmission Paths for EIM Transfers

Given its position relative to CAISO and existing EIM Entities, PGE expects that EIM Transfers will occur (i) directly between the PACW BAA and PGE BAA; and (ii) between the PGE BAA and CAISO using transmission on either the Bonneville Power Administration's ("BPA") or PGE's system, in addition to PGE's rights on the California-Oregon Intertie. With respect to the first category of EIM Transfers, PGE Merchant currently holds 276 MW of long-term point-to-point transmission rights on the PACW to PGE path. PGE Merchant has committed, for the first year of EIM operations, to offer 200 MW of firm transmission rights on the PACW-PGE Path for EIM transfers into the PGE BAA during all market periods. PGE Merchant will also offer the remaining 76 MW of its long-term firm transmission rights, subject to usage for reliability or servicing existing contractual arrangements. In addition, any Available Transfer Capability ("ATC") on this path in excess of PGE Merchant's 276 MW firm reservation will also be made available for EIM Transfers. EIM scheduling availability is determined by subtracting the net of all schedules across the PGE-PACW interface from the Total Transfer Capability between the two entities; the remainder is available for EIM transfers.

²³ Cal. Indep. Sys. Operator Corp., 153 FERC ¶ 61,207 at P 18 (2015).

²⁴ See Cal. Indep. Sys. Operator Corp., 155 FERC ¶ 61,329 (2016) ("CAISO EIM Mitigation Order").

²⁵ See Docket No. ER17-1075.

²⁶ Portland Gen. Elec. Co., Letter Order, Docket No. ER17-1075-000 (issued Apr. 19, 2017).

With respect to EIM Transfers from CAISO to the PGE BAA, three segments will need to be utilized: (1) MALIN to JOHNDAY; (2) JOHNDAY to BPAT.PGE; and (3) BPAT.PGE to PGE. EIM Transfers on this transmission path will require PGE Merchant contributions of firm transmission rights on all three segments.²⁷

II. NOTICE OF CHANGE IN STATUS

The Commission permits sales of energy and capacity at market-based rates if the seller and its affiliates (i) lack horizontal market power in the relevant geographic market, i.e., they do not have (or have adequately mitigated) market power in generation; and (ii) lack vertical market power in the relevant geographic market, i.e., they do not have (or have adequately mitigated) market power in transmission and cannot erect barriers to entry to competing suppliers. As discussed below, PGE does not have horizontal or vertical market power in the relevant market—the EIM Footprint. In addition, the PGE BAA is not a submarket within the EIM Footprint requiring a separate market power analysis.

A. PGE Lacks Horizontal Market Power in the EIM Footprint.

The Commission reviews horizontal market power by assessing the market power of the seller and any of its affiliates that own generation or control generation in the relevant market through tolling agreements, energy management agreements, or other

While PGE Merchant does not hold long-term firm BPA transmission rights on the JOHNDAY to BPAT.PGE segment, it does hold long-term firm BPA transmission rights capable of redirecting to the JOHNDAY to BPAT.PGE segment.

Market-Based Rates for Wholesale Sales of Elec. Energy, Capacity and Ancillary Servs. by Pub. Utils., Order No. 697, 2006–2007 FERC Stats. & Regs., Regs. Preambles ¶ 31,252 ("Order No. 697"), clarified, 121 FERC ¶ 61,260 (2007), order on reh'g and clarification, Order No. 697-A, 2008-2013 FERC Stats. & Regs., Regs. Preambles ¶ 31,268 ("Order No. 697-A"), order on reh'g and clarification, 124 FERC ¶ 61,055, order on reh'g and clarification, Order No. 697-B, 2008-2013 FERC Stats. & Regs., Regs. Preambles ¶ 31,285 (2008), order on reh'g and clarification, Order No. 697-C, 2008-2013 FERC Stats. & Regs., Regs. Preambles ¶ 31,291 (2009), order on reh'g and clarification, Order No. 697-D, 2008-2013 FERC Stats. & Regs., Regs. Preambles ¶ 31,305, order on clarification, 131 FERC ¶ 61,021, reh'g denied, 134 FERC ¶ 61,046 (2010), appeal docketed sub nom. Mont. Consumer Counsel v. FERC, Nos. 08-71827, et al. (9th Cir. filed May 1, 2008); see also Heartland Energy Servs., Inc., 68 FERC ¶ 61,223, at pp. 62,060-63 (1994); Enron Power Enter. Corp., 52 FERC ¶ 61,193, at 61,708 (1990); FirstEnergy Servs., Inc., 94 FERC ¶ 61,052 (2001).

²⁹ PacifiCorp, 147 FERC ¶ 61,227, at P 206 (defining the EIM as "a new relevant geographic market for market power purposes," and holding that commencing participation therein represents a change from the facts and circumstances the Commission relied upon in granting a seller MBR authority.).

³⁰ Ariz. Pub. Serv. Co., 156 FERC ¶ 61,148, at P 28 (holding that EIM participants are "permitted to demonstrate that there are no frequently binding transmission constraints that would limit imports into its home balancing authority area (or the balancing authority area where its generation is located) such that the home balancing authority area should not be deemed to be an EIM submarket itself, or to be within an EIM submarket." The Commission explained that, "[h]aving made such a demonstration, there would be no need for a seller to submit a separate market power analysis for its home balancing authority area.").

contractual arrangements.³¹ The Commission has indicated that the relevant geographic market is the BAA or submarket, as applicable, where the seller's generation is physically located.³² In the case of the EIM, however, the Commission's guidance has been to define the "relevant geographic market to be the combined geographic footprint" of the BAAs constituting the EIM.³³

Mr. Arenchild conducted a market power analysis in which he analyzed the generation owned or controlled by PGE within the EIM Footprint during the December 2014 to November 2015 study period.³⁴ Mr. Arenchild's analysis demonstrates that PGE passes the Commission's indicative pivotal supplier and market share screens when the EIM Footprint as a whole is evaluated as the relevant geographic market. Order No. 697 provides that if a seller passes both of the indicative screens, there is a rebuttable presumption that it does not possess horizontal market power.³⁵

1. Mr. Arenchild Conducted Wholesale Market Share and Pivotal Supplier Screens Utilizing Assumptions that Are Consistent with the Commission's Guidance to EIM Participants.

As further discussed in Mr. Arenchild's Affidavit, PGE passes both the pivotal supplier and market share screens in the EIM Footprint. For this market power study, Mr. Arenchild has utilized the Commission's current indicative Pivotal Supplier Analysis ("PSA") and Market Share Analysis ("MSA") screens, with some modifications to reflect the unique characteristics of the EIM. The PSA screen compares the amount of uncommitted capacity owned or controlled by a seller in the relevant market and the total net uncommitted capacity in that market. If the seller's uncommitted capacity in the market is less than the difference between the total uncommitted supply and the market's wholesale load, the seller passes the pivotal supplier screen. The MSA screen calculates the seller's share of uncommitted capacity in the relevant market during each of the four seasons. If a seller's share of uncommitted capacity in the relevant market is under 20% in each season, the seller passes the market share screen.

³⁴ Mr. Arenchild's Affidavit and supporting exhibits are attached hereto as Attachment B ("Arenchild Aff.").

See Order No. 697 at P 232 n.261; AEP Power Mktg., Inc., 107 FERC \P 61,018, at P 73 n.63, order on reh'g, 108 FERC \P 61,026 (2004).

³² See Order No. 697 at P 231; see also AEP Power Mktg., Inc., 107 FERC \P 61,018, at P 41, order on reh'g, 108 FERC \P 61,026, at P 31.

NV Energy EIM Order at P 202.

³⁵ See Order No. 697 at P 62; see also 18 C.F.R. § 35.37(c)(1). PGE further commits to comply with all applicable CAISO market rules regarding market monitoring and mitigation. The Commission has adopted a rebuttable presumption that existing Commission-approved market monitoring and mitigation rules are sufficient to address any market power concerns. See Order No. 697-A at P 111; see also NextEra Energy Power Mktg., LLC, Letter Order, Docket Nos. ER09-832-004, et al. (issued Mar. 25, 2010).

³⁶ Order No. 697 at P 42; *AEP Power Mktg., Inc.*, 107 FERC ¶ 61,018, at P 99.

To analyze the EIM relevant geographic market, Mr. Arenchild made three adjustments to the standard indicative screen framework to: (i) account for the existence of Participating Resources, which are generating resources in the EIM BAAs that are eligible to submit economic incremental and decremental bids to the EIM, and non-participating resources, which do not submit bids but which can still be used to meet base schedules in the EIM; (ii) adjust the load metric used to determine the amount of generation committed to serve an entity's customers' demand, to reflect "Base Schedule" amounts, rather than actual load; and (iii) calculate expected demand for imbalance energy during the time of the system peak, used in the PSA, using information on the average size of the EIM demand for imbalance energy in each BAA in the EIM Footprint relative to the total energy demand, instead of the proxy for wholesale load used in the standard indicative screens.³⁷ Each of these adjustments is consistent with the EIM-related customizations performed by PSE in the EIM market power analysis which the Commission relied on in authorizing PSE to transact in the EIM at market-based rates.³⁸

2. The Results of the Indicative Screens Conducted by Mr. Arenchild Demonstrate that PGE Lacks Market Power in the EIM.

Given PGE's relatively small presence in the 7-BAA EIM Footprint, it is not surprising that PGE easily passes the indicative screens. As Mr. Arenchild observes, PGE's share of total resources in the overall EIM is about 4%, its share of EIM Participating Resources is just 3%, and PGE's average summer peak load is 5% of the peak load in the EIM Footprint.³⁹

Indeed, Mr. Arenchild shows that PGE passes the PSA because its uncommitted capacity (assessed at 342 MW) is well below the net uncommitted supply (18,906 MW) in the EIM during average hydro and wind conditions, with similar results in five-year high and low hydro/wind production scenarios. Additionally, the MSA shows that PGE's uncommitted capacity varies between 265 MW and 407 MW by season, which amounts to only 1.1%-1.5% of the market—well below the Commission's 20% threshold. Mr. Arenchild also examines several alternative methodologies, including an estimation of a merit order supply curve, and 5- and 15-minute forecasts instead of day-ahead forecasts. PGE passes these versions of the screens, with results not materially different from the baseline PSA and MSA.

³⁷ Arenchild Aff. at 5-6.

³⁸ See Puget Sound Energy, Inc., 156 FERC ¶ 61,242, at P 8.

³⁹ Arenchild Aff. at 24.

⁴⁰ *Id.* at 25.

⁴¹ *Id.* at 26.

⁴² *Id.* at 27-28.

⁴³ *Id.* at 28. None of the alternative methodologies resulted in an estimation of PGE's uncommitted capacity higher than 1.5% of the market. *Id.* at 26.

Accordingly, it is clear from Mr. Arenchild's analysis that PGE lacks market power in the EIM Footprint.

B. PGE Lacks Vertical Market Power.

To demonstrate a lack of vertical market power, an applicant that owns, operates, or controls transmission facilities must have an OATT on file with the Commission. 44 When evaluating vertical market power, the Commission also has adopted a rebuttable presumption that ownership or control of, or affiliation with an entity that owns or controls, inputs to electric power production does not allow a seller to raise barriers to entry to power markets. 45 The Commission, however, requires sellers to provide a description of their ownership of, or affiliation with entities that own or control, such facilities. 46

PGE continues to lack vertical market power. As noted above, the transmission facilities owned by PGE are subject to the terms and conditions of a Commission-approved OATT, ⁴⁷ and all requests for transmission service over transmission facilities owned by PGE are governed by Commission-approved OATTs. The Commission has found that an OATT is deemed to mitigate a seller's vertical market power. ⁴⁸

PGE does not have the ability to erect other barriers to entry by competing suppliers. PGE's only natural gas pipeline interests are in the 17-mile Kelso-Beaver interstate natural gas pipeline, which directly connects PGE's Port Westward and Beaver facilities to the Northwest Pipeline. PGE's portion of the pipeline is a dedicated facility used to supply PGE power plants and operates under the Commission's open-access provisions. The Commission held in Order No. 697 that ownership of natural gas pipelines cannot create a barrier to entry that can be used to exercise vertical market power if the owner provides open-access transportation under a Commission-approved tariff.⁴⁹

In any event, PGE affirms it has not erected barriers to entry in the relevant market and will not erect barriers to entry in the relevant market. Accordingly, PGE does not have vertical market power.

⁴⁴ 18 C.F.R. § 35.37(d); *Puget Sound Energy, Inc.*, Letter Order, Docket Nos. ER12-409-000, et al. (issued Jan. 6, 2012) (accepting for filing PSE's revised OATT in compliance with FERC's eTariff requirements); *Puget Sound Energy, Inc.*, Letter Order, Docket No. ER13-832-000 (issued Mar. 12, 2013) (accepting for filing PSE's most recent revisions to its OATT).

⁴⁵ See Order No. 697 at PP 446-48.

⁴⁶ 18 C.F.R. § 35.37(e)(1)-(3).

⁴⁷ Portland Gen. Elec. Co., 122 FERC ¶ 61,226 (2008).

⁴⁸ See Order No. 697 at P 21.

⁴⁹ *Id.* at PP 441-43.

C. The PGE BAA Is Not a Submarket within the EIM Footprint.

As explained by the Commission in *Arizona Public Service Co.* ⁵⁰ and applied in *Puget Sound Energy, Inc.*, ⁵¹ an EIM participant that demonstrates its home BAA is not an EIM submarket by showing an absence of frequently binding constraints need not submit a separate market analysis for its home BAA. The attached affidavits of Mr. Arenchild and Mr. Gill Sanford affirmatively demonstrate that the PGE BAA is not an EIM submarket.

1. The Demand for Imbalance Energy in the PGE BAA Will Be Significantly Less Than 200 MW.

To assess whether PGE's interconnection with PACW is appropriately sized and sufficiently free of congestion so as to preclude the existence of a PGE BAA submarket, it is first essential to quantify the anticipated demand for imbalance energy within the PGE BAA. To do so, Mr. Arenchild utilized 1-minute BAA load data provided by PGE for the Study Period (which were aggregated into 15-minute intervals), as well hourahead load forecasts, to compute the demand for imbalance energy in the PGE BAA in each of the 35,036 15-minute intervals during the Study Period. This approach is consistent with the approach utilized by PSE to quantify the demand for imbalance energy in the PSE BAA. During the Study Period, Mr. Arenchild determined the average-deviation from the hour ahead forecast was 45 MW, with 95% of all 15-minute operating intervals having deviations between plus/minus 117 MW. Negative deviations (giving rise to a need for incremental imbalance energy) exceeded 200 MW in only 0.039% of all 15-minute intervals during the Study Period. Mr. Arenchild "also analyzed whether the load deviations would significantly differ using five-minute actual data and found that there was very little difference."

During the Study Period, load was the only source of system variability giving rise to the need for imbalance energy, as there were no significant variable energy resources electrically located within the PGE BAA. As Mr. Arenchild notes, this circumstance is likely to change in the next year as PGE expects that two large wind farms that it controls, Biglow Canyon Wind Farm (450 MW) and Tucannon River Wind Farm (267 MW), which are presently balanced by BPA, will be pseudo-tied into the PGE BAA. Mr. Arenchild utilized hour-ahead forecasts and 15-minute generation data for these plants during the Study Period to quantify the adjusted demand for imbalance

⁵⁰ See Ariz. Pub. Service Co., 156 FERC ¶ 61,148, at P 28.

⁵¹ *See Puget Sound Energy, Inc.*, 156 FERC ¶ 61,242, at P 23.

⁵² Arenchild Aff. at 30-32 & tbl. 1.

⁵³ Puget Sound Energy, Inc., 156 FERC ¶ 61,242, at P 12.

⁵⁴ Arenchild Aff. at 32.

⁵⁵ *Id.* at 31.

⁵⁶ *Id.* at 9-10, 33.

energy in the PGE BAA as though the plants were included.⁵⁷ Mr. Arenchild describes an average deviation of 69 MW and an adjusted 95th percentile deviation of plus/minus 183 MW, with just 1.6% of all 15-minute intervals exhibiting a demand for incremental imbalance energy in excess of 200 MW.⁵⁸

Mr. Arenchild concludes, based on the expected size of the market and the existence of at least 200 MW of firm transmission capacity during all market intervals to support imports of in-hour imbalance energy dispatched by the EIM, "the available import capability is sufficiently greater than expected demand in the PGE BAA in essentially all intervals." ⁵⁹

2. Sufficient Transmission Capacity Will Be Available for EIM Imports to Ensure a Competitive External Supply of Generation to Serve EIM Demand in the PGE BAA.

Mr. Arenchild's Affidavit described above demonstrates that the demand for imbalance energy within the PGE BAA is likely to average 45 MW (69 MW with wind), and remain less than 117 MW (183 MW with wind) during 95% of 15-minute scheduling intervals. Mr. Gill Sanford's Affidavit demonstrates that sufficient transmission capacity will be available to ensure that a competitive supply of external, non-PGE generation from the EIM Footprint will be available from EIM import transfers to compete with PGE generation for the anticipated imbalance energy demand in the PGE BAA.

a. PGE Merchant's Contribution of at Least 200 MW of Firm Transmission Rights on the PACW to PGE Path Will Provide Sufficient Firm Import Capability to Meet the Demand for Imbalance Energy With Competitive External Generation.

Mr. Gill Sanford's Affidavit describes two transmission paths that will be available for imports of competitive imbalance energy supply into the PGE BAA: (1) PACW to PGE; and (2) CAISO to PGE. The first path will be available by virtue of PGE Merchant's 276 MW of long-term point-to-point transmission rights, of which PGE Merchant has committed to contribute a minimum of 200 MW for EIM Transfers during each market interval for at least the first year of EIM operations. PGE will offer the remaining 76 MW of its long-term firm rights on the path for EIM Transfers, subject to usage for reliability or servicing existing contractual arrangements. As Mr. Gill Sanford explains, the PACW to PGE path consists of two segments: (i) PACW to PACW.PGE, for which PacifiCorp is the transmission provider; and (ii) PACW.PGE to PGE, for

⁵⁷ *Id.* at 33-34.

⁵⁸ *Id.* at 28.

⁵⁹ *Id.* at 29.

⁶⁰ *Id.* at 32-34 & tbl. 3.

which PGE is the transmission provider. Mr. Gill Sanford gathered congestion data on the PacifiCorp and PGE systems by querying OASIS messages and archived e-Tags and determined that there were zero instances of transmission congestion (firm or non-firm) on the PACW to PACW.PGE transmission path and zero instances of transmission congestion (firm or non-firm) on the PACW.PGE to PGE transmission path during the Study Period. Based on the historical lack of congestion, Mr. Gill Sanford concludes that there is a "high likelihood of the inbound transfer capacity being unhindered by congestion events during all market intervals."

 Additional Sources of Transmission Capacity Will Increase the PGE BAA's EIM Transfer Import Capability Above the Minimum Value of 200 MW.

As Mr. Gill Sanford's analysis shows, at least 200 MW of firm import capability is likely to exist for EIM Transfers due to the 200 MW of firm transmission that will be contributed by PGE Merchant on the historically unconstrained PACW to PGE path in every market interval during at least the first year of EIM operations. In addition to the 200 MW minimum commitment, PGE Merchant will contribute its remaining 76 MW of long-term firm rights on this path when it is not being used for reliability or to service existing contractual arrangements. This firm import capability by itself will be sufficient to ensure a competitive supply of imported generation to meet the likely demand for imbalance energy in the PGE BAA computed by Mr. Arenchild. Mr. Gill Sanford also describes the potential availability of additional non-firm ATC on the PACW to PGE path in his affidavit. 62 As Mr. Gill Sanford notes, total transfer capability ("TTC") on the PACW.PGE to PGE segment of the path (which is the limiting segment for the path) ranges from a summer rating of 305 MW to 415 MW in the winter months.⁶³ Accordingly, the total availability of the PACW to PGE path for EIM imports will vary from a minimum of 200 MW (corresponding to the minimum firm contribution of PGE Merchant) to 415 MW, depending on the season, PGE Merchant usage of its residual 76 MW of firm rights, and the availability of non-firm ATC leading up to the operating hour. 64 As Mr. Gill Sanford explains, the PACW to PGE path would have supported EIM transfers of 252 MW on average during the study period using the combination of PGE Merchant's firm rights and additional as available capacity. 65

In addition to EIM imports on the PACW to PGE path, the CAISO to PGE path may also be available for EIM imports. This path consists of three segments: (1) MALIN to JOHNDAY; (2) JOHNDAY to BPAT.PGE; and (3) BPAT.PGE to PGE. PGE is the transmission provider on the first and third segments, and BPA is the transmission provider on the second segment. Mr. Gill Sanford's analysis of congestion history on

⁶¹ Affidavit of Zachary A. Gill Sanford at 3 (attached hereto as Attachment C).

⁶² *Id.* at 4-5.

⁶³ *Id.* at 5.

⁶⁴ *Id*.

⁶⁵ *Id.* at 3.

these segments during the Study Period showed zero instances of congestion on all three segments. He is a segment of the CAISO to PGE path. EIM Transfers on this import path will require PGE Merchant contributions of firm transmission capacity on all three segments. He is a firm transmission capacity on all three segments. He is a firm transmission capacity on all three segments. He is a firm transmission capacity on the segments of the MALIN to JOHNDAY segment and the availability of firm ATC on the BPAT. He is a minimum of 85 MW and a maximum of 627 MW of transfer capacity available for EIM import transfers on the CAISO to PGE path during intervals the PGE merchant offers its transmission rights. He is a segment of the property of the path during intervals the property of the property

In sum, it is apparent that a minimum of 200 MW of transmission capacity is likely to be available for EIM imports during all market intervals on the PACW to PGE path, with additional amounts likely to be available during certain market intervals ranging from (i) 0 MW to 215 MW of additional PGE Merchant long-term firm rights and non-firm ATC on the PACW to PGE path, depending on the season and transmission customer scheduling behavior; and (ii) 85 MW to 627 MW on the CAISO to PGE path when PGE Merchant contributes its firm rights. The minimum 200 MW transfer path provide sufficient import capability to supply the PGE BAA's imbalance energy demand in virtually all market intervals. In combination with other potential sources of import capability, there is likely to be more than ample transmission capacity to ensure a competitive supply of external generation to meet the PGE BAA's energy imbalance demand. As such, the PGE BAA is not a submarket within the EIM footprint requiring a separate market power analysis.

3. The CAISO Tariff Currently Provides for Mitigation of Non-Competitive Supply Offers in the Unlikely Event that a Transmission Constraint Binds between PACW and PGE.

The foregoing analysis demonstrates that, based on the anticipated average 45 MW quantity of demand for imbalance energy in the PGE BAA, and the 200 MW commitment of firm, unconstrained transmission between the PACW BAA and the PGE BAA (in addition to other transmission capacity for imports that may be made available on the PACW to PGE and CAISO to PGE paths), it is likely that PGE will be competing with non-PGE generation from outside the PGE BAA for every MW of demand for imbalance energy in the PGE BAA at all times. However, in the unlikely event that a transmission constraint were to result in non-competitive supply offers within the PGE BAA, the application of Commission-accepted, enhanced market monitoring and mitigation measures to constrained internal paths and interties between the seven BAAs in the EIM Footprint will ensure that PGE and other sellers cannot exercise market power. PGE's intertie with the PACW BAA will be monitored by the Department of

⁶⁶ *Id*. at 6.

⁶⁷ *Id.* at 7. As noted above, while PGE Merchant does not hold long-term firm BPA transmission rights on the JOHNDAY to BPAT.PGE segment, it does hold long-term firm BPA transmission rights capable of redirecting to the JOHNDAY to BPAT.PGE segment.

⁶⁸ *Id.* at 8.

Market Monitoring ("DMM") as part of every market interval for price separation indicative of a binding constraint. ⁶⁹ Pursuant to Section 29.39 of its tariff, CAISO conducts a competitive path assessment for each EIM Entity BAA, performs an LMP decomposition identifying any resources in the EIM which may have local market power due to a transmission constraint, and mitigates any such resources using DEBs. As noted above, CAISO's mitigation measures have recently been enhanced to include mitigation at 5-minute intervals as well as 15-minute intervals.

In its 2016 CAISO EIM Mitigation Order, the Commission accepted proposed revisions to Section 29.39 of the CAISO Tariff providing that CAISO's "Real-Time Local Market Power Mitigation procedure in Section 39.7" of the CAISO Tariff will be applied "to the Energy Imbalance market, *including EIM Transfer constraints into an EIM [BAA] on an EIM Internal Intertie.*" CAISO's full network model simulates market outcomes using real time transmission information from the entire EIM Footprint, including any anticipated transfer or ramping restrictions on BPA's internal flowgates and the interties between the PACW and PGE BAAs. In the unlikely event that CAISO's model identifies price separation resulting from a binding constraint on the 200 MW transfer path from PACW to PGE, CAISO's DMM would test this constraint for competitiveness in accordance with the local market power mitigation measures described in Section 39.7.2 of the CAISO Tariff. Under these provisions, a generator's energy bids will be subject to mitigation in the event that congestion occurs and the supply that can relieve the congestion is deemed uncompetitive. A constrained path is designated as non-competitive when

the sum of the supply counter-flow from all portfolios of potentially pivotal suppliers to the Transmission Constraint and the fringe supply of counter-flow to the Transmission Constraint from all portfolios of suppliers that are not identified as potentially pivotal is less than the demand for counter-flow to the Transmission Constraint.⁷⁵

If subject to mitigation, energy bids are capped by the higher of a competitive market clearing price or the DEB.⁷⁶ The bidding resource can only be dispatched based on its

⁶⁹ See CAISO EIM Mitigation Order. The revisions to Section 29.39 of the CAISO Tariff extending local market power mitigation to interties between EIM BAAs became effective on October 1, 2016.

⁷⁰ See supra note 16.

⁷¹ CAISO Tariff § 29.39(a) (emphasis added).

⁷² In addition to the predictive capabilities of the CAISO full network model at forecasting congestion, PGE is also required to notify CAISO once PGE receives notification that an e-Tag supporting an EIM transfer has been curtailed.

⁷³ See CAISO Tariff § 39.7.

⁷⁴ See id. See also id. § 34.1.5 (describing mitigation of bids in the real-time market).

⁷⁵ *Id.* § 39.7.2.2(b).

⁷⁶ See id. § 39.7.1 (describing calculation of DEB).

mitigated bids during the ensuing market interval, when the energy produced by the resource is necessary to meet a local need within an non-competitive area.⁷⁷

In the CAISO EIM Mitigation Order, FERC concluded that "CAISO's proposal to always include EIM transfers into every EIM Entity BAA in its market power mitigation procedures will ensure that all EIM internal interties will be mitigated whenever conditions warrant, and will result in consistent treatment of all constraints in the EIM area." Thus, while PGE does not expect frequently binding constraints on the PACW to PGE transfer path, CAISO's application of local market power mitigation to this intertie will prevent PGE from exercising market power in the event a binding constraint does arise that is deemed to be non-competitive by the DMM.

III. <u>COMMUNICATIONS</u>

Communications with regard to this filing should be addressed to:

*Donald Light
Portland General Electric Company
121 SW Salmon Street
1WTC1301
Portland, OR 97204
Tel: (503) 464-8315
donald.light@pgn.com

Gary D. Bachman
Justin P. Moeller*
Van Ness Feldman LLP
Seventh Floor
1050 Thomas Jefferson Street, NW
Washington, DC 20007
Tel: (202) 298-1800
gdb@vnf.com
jpx@vnf.com

IV. REQUEST FOR PRIVILEGED TREATMENT

Pursuant to section 388.112 of the Commission's regulations, PGE requests privileged treatment of certain workpapers filed in support of the Affidavit prepared by Mr. Arenchild, because these workpapers contain information that is privileged or confidential and not publicly available. The information contained in these privileged workpapers is for use by the Commission's Staff only and should not be released. Pursuant to section 388.112(b)(2)(i), a proposed form of protective agreement is attached as Attachment D.

^{*} Designated for service of process

⁷⁷ See id. § 34.1.5.

see ia. § 54.1.5.

⁷⁸ CAISO EIM Mitigation Order at P 36 (emphasis added).

V. <u>ATTACHMENTS</u>

A. Public

PGE submits the following public documents:

This transmittal letter, along with the following attachments:

- Attachment A: PGE Appendix B Market-Based Rate Authority Asset Appendix
- <u>Attachment B</u>: Affidavit, Exhibits, and public work papers of Matthew E. Arenchild
- Attachment C: Affidavit and Exhibits of Zachary A. Gill Sanford
- Attachment D: Protective Agreement

B. Non-Public

PGE submits the following non-public documents:

• Attachment E: Non-public work papers supporting the Arenchild Affidavit

VI. <u>CONCLUSION</u>

For the reasons set forth above, PGE requests that the Commission accept this change of status for filing prior to October 1, 2017 and authorize PGE to transact in the EIM at market-based rates.

Respectfully submitted,

/s/ Justin P. Moeller

Gary D. Bachman
Justin P. Moeller
Van Ness Feldman LLP
1050 Thomas Jefferson Street, NW
Seventh Floor
Washington, DC 20007
Tel: (202) 298-1800
gdb@vnf.com
jpx@vnf.com

Attorneys for Portland General Electric Company

Attachments

UM 1829 PGE Response to Blue Marmot DR No. 2 Attachment 2 A Page 19 Blue Marmot/301 Moyer/20

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused to be served the foregoing document upon each person designated on the official service lists compiled by the Secretary in in the above-captioned proceedings.

Dated at Washington, D.C. this 16th day of June, 2017.

/s/ Justin P. Moeller
Justin P. Moeller
Van Ness Feldman LLP
1050 Thomas Jefferson Street, NW
Seventh Floor
Washington, DC 20007
Tel: (202) 298-1800

July 7, 2017

TO: Irion Sanger

Leslie Freiman Will Talbott

FROM: Karla Wenzel

Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC UM 1829

PGE Response to Blue Marmot Data Request No. 18 Dated June 23, 2017

Request:

18. Please analyze the TTC at PACW.PGE including Blue Marmot's TSRs (i.e., including all of Blue Marmot's proposed generation on PAC's side and none of PGE's generation) to determine whether the TTC increases.

Response:

Pursuant to OAR 860-001-0500(4), PGE objects that this request requires PGE to conduct an analysis which is unduly burdensome and is not highly relevant. PGE's analysis of TTC at PACW.PGE is represented in the values posted on OASIS.

July 7, 2017

TO: Irion Sanger

Leslie Freiman Will Talbott

FROM: Karla Wenzel

Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC UM 1829

PGE Response to Blue Marmot Data Request No. 22 Dated June 23, 2017

Request:

22. Please identify all offsystem QFs that have entered into PPAs with PGE. Please identify the POD for each contract, when PGE requested that the QF identify the POD, and the amount of ATC available at the time of contract execution. Please provide a complete and nonredacted copy of all offsystem QF contracts that are not posted on the OPUC's website in docket number RE 143.

Response:

PGE objects to this request on the grounds that it is overly broad and unduly burdensome and seeks information that is neither relevant nor calculated to lead to the discovery of relevant evidence. Alternatively, the information sought is more prejudicial than it is probative. Without waiving its objections, PGE responds as follows. PGE has filed its PPAs, or summaries of PPAs, with off-system QFs in OPUC Docket No. RE 143. The POD for the Airport Solar Schedule 202 contract is PACW. PGE generally began requesting that QFs identify PODs on or about April 18, 2017.

July 7, 2017

TO: Irion Sanger

Leslie Freiman Will Talbott

FROM: Karla Wenzel

Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC UM 1829

PGE Response to Blue Marmot Data Request No. 23 Dated June 23, 2017

Request:

23. Will PGE accept deliveries from other offsystem QFs that have entered into PPAs with PGE and/or have requested PPAs from PGE and that are planning to deliver at PACW.PGE?

Response:

PGE is reviewing off-system QFs that have entered PPAs and has not made a determination about whether it can accept deliveries from each of them at this time. All QFs that have requested PPAs from PGE and that have requested to deliver at PACW.PGE will be given the same options as Blue Marmot.

July 19, 2017

TO: Irion Sanger

Leslie Freiman Will Talbott

FROM: Karla Wenzel

Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC UM 1829

PGE Response to Blue Marmot Data Request No. 24 Dated June 23, 2017

Request:

24. If additional ATC is made available at the PACW.PGE POD, how would priority be established PGE accept deliveries from other offsystem QFs that have entered into PPAs with PGE and/or have requested PPAs from PGE and that are planning to deliver at PACW.PGE?

Response:

PGE is in the process of developing a policy to address the circumstances posited in this DR. When that policy is developed, PGE will supplement its response to this DR.

July 17, 2017

TO: Irion Sanger

Leslie Freiman Will Talbott

FROM: Karla Wenzel

Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC UM 1829

PGE Response to Blue Marmot Data Request No. 28 Dated June 23, 2017

Request:

28. Has PGE executed any PPAs for delivery at PACW.PGE since this POD became constrained in PGE's view (i.e., when PGE acquired the long-term firm transmission capability it felt was necessary to fully participate in the EIM) and if so, how will those parties be treated?

Response:

Yes, PGE has entered three PPAs for delivery at PACW.PGE since July 1, 2015. PGE is evaluating how deliveries anticipated to be made from those projects to the PACW.PGE POD will be handled.

August 2, 2017

TO: Irion Sanger

Leslie Freiman Will Talbott

FROM: Karla Wenzel

Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC UM 1829 PGE Response to Blue Marmot Data Request No. 44 Dated July 19, 2017

Request:

44) Does PGE consider PACW.PGE to be a POD on PGE's system?

Response:

PACW.PGE is a scheduling point associated with the PACW OASIS transmission reservation point. PACW.PGE can be used as a valid POD on a NERC e-tag, assuming the party has appropriate transmission rights and the e-tag passes validation rules. The PACW.PGE scheduling point is not a valid sink (i.e. ultimate delivery point) and e-tags are not allowed to terminate at the PACW.PGE scheduling point (i.e. they must continue on to a valid POR or sink).

August 2, 2017

TO: Irion Sanger

Leslie Freiman Will Talbott

FROM: Karla Wenzel

Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC UM 1829 PGE Response to Blue Marmot Data Request No. 45 Dated July 19, 2017

Request:

Would PGE describe PACW.PGE as the edge or border of PGE's balancing authority area?

Response:

Yes. PGE has a PACW.PGE scheduling point on its system in the PGE balancing authority area. PacifiCorp also has a PACW.PGE scheduling point on its system in the PACW balancing authority area. The PACW OASIS transmission reservation point—of which PACW.PGE is one scheduling point—represents the interface between the PGE and PACW transmission systems.

August 2, 2017

TO: Irion Sanger

Leslie Freiman Will Talbott

FROM: Karla Wenzel

Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC UM 1829 PGE Response to Blue Marmot Data Request No. 46 Dated July 19, 2017

Request:

Please identify each point where PGE's transmission system directly connects with PacifiCorp's transmission system. Are there any other points (i.e. unspecified or unmetered points, area where other power is commingled, etc.) where a change in ownership between PacifiCorp and PGE can occur?

Response:

PGE objects to this data request on the grounds that the phrase "where a change in ownership between PacifiCorp and PGE can occur" is neither defined nor used with sufficient precision to enable PGE to know what is intended by the phrase. Without waiving this objection, PGE responds as follows. This path and the corresponding physical points of interconnection are all associated with the PACW OASIS transmission reservation point, which is the only viable OASIS transmission reservation point allowed for import of electricity from the PacifiCorp West system to PGE's system via the PACW-PGE path.

TO: Irion Sanger

Leslie Freiman Will Talbott

FROM: Karla Wenzel

Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC UM 1829

PGE Response to Blue Marmot Data Request No. 49 Dated August 25, 2017

Request:

52. Provide all written communication and a summary of any verbal communication related to AREF 84996127, 19 MW, PACW to PGE, that per Customer (PGEM) notes was "...submitted upon recommendation of TP to request a return of capacity originally recalled that was recently made available due to updated studies. See 81087171." In addition, provide all documents, correspondence, forms, and related materials regarding PGE's updated commitment of PACW.PGE > PGE transmission as EIM Transfer System Resources (ETSR) following PGEM's confirmation of AREF 84996127.

Response:

The 19 MW was identified and reserved in June 2017 by PGE Merchant to alleviate the impact of the transmission capacity that was previously granted in 2015 and subsequently recalled in 2016 by PGE Transmission. Those original reservations and recalls were detailed in PGE's response to Blue Marmot Data Request No. 4. Attachments 52-A and 52-B provide all email correspondence related to the 19 MW, and Attachment 52-C is an internal pre-approval memo related to the 19 MW.

TO: Irion Sanger

Leslie Freiman Will Talbott

FROM: Karla Wenzel

Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC UM 1829

PGE Response to Blue Marmot Data Request No. 49 Dated August 25, 2017

Request:

53. What has PGEM done to verify if there is any transmission from PACW.PGE to PGE?

Response:

PGE objects to this request on the grounds that it is vague and ambiguous, and lacking in any temporal limitation. PGE assumes that this data request concerns the circumstances applicable to Blue Marmot and is seeking information regarding what PGE Merchant has done to verify that there is not sufficient available transfer capability (ATC) for Blue Marmots' projects and that system upgrades would be required in order for Blue Marmot to be able to deliver its energy to the PACW.PGE point of interconnection.

Without waiving its objection, PGE responds as follows. PGE Merchant, like all other transmission customers, identifies ATC by reviewing the information posted on the Open Access Same Time Information System (OASIS), the same website to which Blue Marmot has access.

TO: Irion Sanger

Leslie Freiman Will Talbott

FROM: Karla Wenzel

Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC UM 1829

PGE Response to Blue Marmot Data Request No. 49 Dated August 25, 2017

Request:

Please confirm the date that PGE provided the Blue Marmots with executable PPAs, and that these were provided prior to the identification of the 19 MW mentioned in data request 52 and 53, please explain why PGE did not commit the transmission to the Blue Marmots and sign at least one PPA?

Response:

PGE confirmed the dates that the Blue Marmots were provided with draft and executable PPAs in its answers to the complaints filed in OPUC Docket Nos.UM 1829, UM 1830, UM 1831, UM 1832, and UM 1833:

1/12/17 – executable PPA for Blue Marmot Project VI.

1/16/17 – executable PPA for Blue Marmot Project V.

3/21/17 – executable PPA for Blue Marmot Project VII and executable PPA for Blue Marmot Project IX.

3/22/17 – final draft PPA for Blue Marmot Project VIII. PGE did not provide an executable PPA for Blue Marmot Project VIII due to constraints at the anticipated POD (PACW.PGE) for delivery.

The 19 MW was identified and reserved in June 2017 by PGE Merchant to alleviate the impact of the transmission capacity that was previously granted in 2015 and subsequently recalled in 2016 by PGE Transmission. Those original reservations and recalls were detailed in PGE's response to Blue Marmot Data Request No. 4. Please see the Attachments to PGE's response to Blue Marmot Data Request No. 52 for additional detail regarding the 19 MW.

In addition, there were other QFs ahead of Blue Marmot with which PGE has executed PPAs for delivery at PACW.PGE. Those QFs were identified in PGE's response to Blue Marmot Data Request Nos. 28 and 40.

September 15, 2017

TO: Irion Sanger

Leslie Freiman Will Talbott

FROM: Karla Wenzel

Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC UM 1829 PGE Response to Blue Marmot Data Request No. 55 Dated August 25, 2017

Request:

55. Why did PGEM not determine the availability of 15 MW of LTF-PTP that the Blue Marmots (via SUSP) were informed was available following its TSR for 60 MW (via SUSP).

Response:

Like all transmission customers, PGE Merchant's knowledge of ATC is limited to the information posted on OASIS. Further, since PGE Merchant does not have any transmission requests in study state, it does not receive direct communication regarding ATC that could impact any open requests.

In 2015, PGE Merchant reserved 418 MW of transmission service importing from PACW to PGE for the purpose of participating in the CAISO EIM. 142 MW was recalled in 2016, which reduced PGE's reserved capacity to 276 MW. In June 2017, PGE Merchant noted that changes in TTC had resulted in an additional 19 MW of availability. Because a portion of its original transmission reservations had been recalled, PGE Merchant believed that any increase in available transmission would function to "reload" the recalled amount. PGE Transmission informed PGE Merchant that this was not the case. This is discussed in Attachment 52-A of PGE's response to Blue Marmot Data Request No. 52. Hence, PGE Merchant reviewed OASIS for availability following the TTC change and reserved 19 MW. Because PGE Merchant was focused on reacquiring 19 MW of the previously recalled capacity, it did not find the additional 15 MW that was available further out that was not associated with a change in TTC.

September 11, 2017

TO: Irion Sanger

Leslie Freiman Will Talbott

FROM: Karla Wenzel

Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC UM 1829

PGE Response to Blue Marmot Data Request No. 73 Dated August 28, 2017

Request:

73. Does PGE believe that Blue Marmot's obligations (under PURPA or otherwise) extend beyond making its power available at a POD on PGE's system? Please explain.

Response:

PGE objects to this question as vague and ambiguous. Without waiving its objections, PGE states that off-system QFs are responsible for paying for any necessary costs including studies and upgrades incurred on the QF's behalf to deliver its output to the purchasing utility.

September 15, 2017

TO: Irion Sanger

Leslie Freiman Will Talbott

FROM: Karla Wenzel

Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC UM 1829

PGE Response to Blue Marmot Data Request No. 91 Dated September 1, 2017

Request:

91. Please refer to PGE's response to Blue Marmot data request 23. Please update this response with PGE's "determination."

Response:

PGE still is working to craft its approach to this issue and will update Blue Marmot when it has done so.

September 15, 2017

TO: Irion Sanger

Leslie Freiman Will Talbott

FROM: Karla Wenzel

Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC UM 1829

PGE Response to Blue Marmot Data Request No. 92 Dated September 1, 2017

Request:

92. Please refer to PGE's response to Blue Marmot data request 23. Please identify the PGE current or former employees familiar with whether PGE will accept deliveries from other offsystem QFs that have entered into PPAs with PGE and/or have requested PPAs from PGE and that are planning to deliver at PACW.PGE.

Response:

As noted above, PGE has not yet developed an approach for addressing deliveries from off-system QFs with fully executed PPAs who have indicated that they wish to deliver to the PACW.PGE POD. Once PGE develops its approach regarding QFs with executed contracts, Brett Sims will be able to discuss it. Brett Sims is familiar with PGE's discussions with off-system QFs who have requested PPAs from PGE and indicated that they wish to deliver to the PACW.PGE POD, but do not yet have fully executed PPAs.

TO: Irion Sanger

Leslie Freiman Will Talbott

FROM: Karla Wenzel

Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC UM 1829

PGE Response to Blue Marmot Data Request No. 103 Dated September 5, 2017

Request:

103. Does PGE believe accepting Blue Marmot's delivery would contribute to a system emergency? If so, please explain how accepting Blue Marmot's delivery would result in imminent significant disruption of service to customers or imminently endanger life or property.

Response:

PGE objects to this request as vague and ambiguous. Without waiving its objections, PGE responds as follows. Whether delivery of Blue Marmot's output would harm system reliability depends on a number of variables. For instance, if PGE were required hypothetically to accept delivery of Blue Marmot's output in addition to its usage of the PACW-PGE path as planned for the EIM, this could result in usage of the path above its TTC. PGE cannot operate a path above the path's TTC because doing so could be detrimental to system reliability.

TO: Irion Sanger

Leslie Freiman Will Talbott

FROM: Karla Wenzel

Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC UM 1829

PGE Response to Blue Marmot Data Request No. 104 Dated September 5, 2017

Request:

104. Please refer to FERC Order 69 at ¶ 30,886. Does PGE believe accepting Blue Marmot's delivery would involve this type of operational circumstances, which can occur during light-loading conditions? If so, please explain how accepting Blue Marmot's delivery would result in this scenario.

Response:

PGE objects to this question to the extent that it requests a legal conclusion, and PGE objects that the phrase "this type of operational circumstances" is vague, ambiguous, and undefined. Without waiving its objection, and assuming Blue Marmot's question refers to the situation described in 18 C.F.R. § 292.304(f), PGE responds as follows: Based on current conditions, PGE does not anticipate this type of circumstance. The reason Blue Marmot cannot deliver its power to PGE on the PACW-PGE path is the lack of ATC.

TO: Irion Sanger

Leslie Freiman Will Talbott

FROM: Karla Wenzel

Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC UM 1829

PGE Response to Blue Marmot Data Request No. 105 Dated September 5, 2017

Request:

105. Please refer generally to PGE's OATT. Does PGE believe that insufficient ATC is available to grant a network resource designation to Blue Marmot? Please explain why or why not.

Response:

Currently, there is insufficient ATC to grant Blue Marmot a network resource designation and maintain PGE Merchant's firm point-to-point transmission rights on the PACW-PGE path for use in the EIM. If, hypothetically, PGE Merchant were to request a network resource designation for Blue Marmot, PGE Transmission would determine whether the designation could be granted. Therefore, given the lack of ATC, if PGE Transmission were to grant the request, PGE Transmission would reallocate a portion of PGE Merchant's firm point-to-point transmission rights on the path to network transmission, which would unacceptably limit PGE's access to the long-term firm transmission required for the EIM.

UM 1829 PGE Response to Blue Marmot's Sixth Set of Data Requests

Blue Marmot/301 Moyer/39

September 28, 2017

TO: Irion Sanger

Leslie Freiman Will Talbott

FROM: Karla Wenzel

Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC UM 1829

PGE Response to Blue Marmot Data Request No. 106 Dated September 5, 2017

Request:

106. Please refer generally to PGE's OATT. Did PGE Merchant formally request a new network designation for Blue Marmot? Please explain why or why not.

Response:

No, neither PGE's OATT nor PURPA requires PGE to do so. Please see PGE's response to Blue Marmot Data Request No. 105.

TO: Irion Sanger

Leslie Freiman Will Talbott

FROM: Karla Wenzel

Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC UM 1829

PGE Response to Blue Marmot Data Request No. 107 Dated September 5, 2017

Request:

107. Please refer generally to PGE's OATT. Did PGE Merchant request a study in connection with the designation of a new network resource delivered off of the PACW system? Please explain why or why not.

Response:

PGE objects to this request as vague, ambiguous, and lacking in any temporal specificity. Without waiving its objections, PGE responds as follows. No, PGE Merchant has not requested designation of any new network resources delivering from the PACW system since March 2015. If PGE Merchant were to request to designate a new network resource delivering from the PACW system, PGE Merchant would not request a study; rather PGE Transmission would decide whether a study was necessary. The process for a study for network integration transmission service would be handled pursuant to Part III of PGE's OATT.

TO: Irion Sanger

Leslie Freiman Will Talbott

FROM: Karla Wenzel

Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC UM 1829

PGE Response to Blue Marmot Data Request No. 108 Dated September 5, 2017

Request:

108. Please refer generally to PGE's OATT. Is PGE Transmission obligated to build any network upgrades required to integrate any and all designated network resources of PGE Merchant and to roll those costs into transmission rates?

Response:

No, PGE Transmission is not obligated to build "any network upgrades required to integrate any and all designated resources." Numerous environmental, engineering, legal, and economic factors would need to be assessed prior to building any Network Upgrades, as defined in PGE's OATT. If PGE were to determine Network Upgrades were required, those costs would be rolled into transmission rates. However, there may be other facilities required to integrate designated network resources into PGE's transmission system that do not qualify as Network Upgrades, in which case certain costs may be allocated directly to the Transmission Customer.