BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

AR 622

In the Matter of Rulemaking for Community-Based Renewable Energy Projects.	JOINT COMMENTS OF THE COMMUNITY RENEWABLE ENERGY ASSOCIATION AND THE RENEWABLE ENERGY ASSOCIATION IN RESPONSE TO STAFF REQUEST FOR REPONSES

INTRODUCTION

The Community Renewable Energy Association ("CREA") and the Renewable Energy Coalition ("REC") submit these Joint Comments in Response to the Public Utility Commission of Oregon ("OPUC" or "Commission") Staff's Request for Responses distributed on September 19, 2018.

CREA and REC appreciate the opportunity to comment on this proposed rulemaking for small-scale community-based renewable energy generation facilities, as required by ORS 469A.210. This rulemaking is central to the mission of both CREA and REC because both organizations have the mission of advocating for policies to will lead to successful development and operation of small-scale community-based renewable energy generation facilities in Oregon. CREA and REC believe that the Oregon legislature has also unambiguously expressed support for such policies, through its longstanding statutory provisions regarding Oregon's implementation of the Public Utility Regulatory Policy Act of 1978 ("PURPA"), ORS 758.505 *et seq*, and through the recent reaffirmation of the state's eight-percent requirement for small-scale community-based renewable energy generation facilities in ORS 469A.210. The Commission is the state agency that the legislature has charged with implementing this important eight-percent requirement and related policies.

As explained in response to the Staff's specific inquiries below, CREA and REC urge the Commission to promptly implement administrative rules that will ensure that Oregon's eight-percent requirement for small-scale community-based renewable energy generation facilities is met by the major Oregon investor-owned utilities (defined as "electric companies" in Oregon law). Proper implementation of the statutory eight-percent requirement through administrative rules is critical to ensure that the legislature's intent is realized.

COMMENTS

The purpose of this rulemaking is to implement and ensure compliance with the Oregon legislature's directive that is intended to promote small-scale community-based renewable generation facilities of 20 megawatts ("MW") of generating capacity or less and certain biomass cogeneration. This requirement was formerly identified in the original version of Oregon's renewable portfolio standard ("RPS") as a "goal" that administrative agencies of the executive branch were charged with achieving. *See* 2007 Oregon Laws, ch 301, § 24.[1] In 2016, among other modifications, the eight-percent goal was converted at an affirmative requirement no less

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[1] This provision provided:

> Goal for community-based renewable energy projects. The Legislative Assembly finds that community-based renewable energy projects are an essential element of Oregon's energy future, and declares that it is the goal of the State of Oregon that by 2025 at least eight percent of Oregon's retail electrical load comes from small-scale renewable energy projects with a generating capacity of 20 megawatts or less. All agencies of the executive department as defined in ORS 174.112 shall establish policies and procedures promoting the goal declared in this section.

Id.

significant than the RPS's other compliance requirements, *see* 2016 Oregon Laws, ch 28, § 14, and in 2017, a further amendment clarified that the facilities meeting the eight-percent requirement must be small-scale community-based facilities that also qualify under the general RPS criteria in ORS 469A.025. *See* 2017 Oregon Laws, ch 452, § 1.

The critical statutory language in the current version of ORS 469A.210 provides:

> (1) The Legislative Assembly finds that community-based renewable energy projects, including but not limited to marine renewable energy resources that are either developed in accordance with the Territorial Sea Plan adopted pursuant to ORS 196.471 or located on structures adjacent to the coastal shorelands, are an essential element of this state's energy future.
>
> (2) For purposes related to the findings in subsection (1) of this section, by the year 2025, at least eight percent of the aggregate electrical capacity of all electric companies that make sales of electricity to 25,000 or more retail electricity consumers in this state must be composed of electricity generated by one or both of the following sources:
>
> > (a) Small-scale renewable energy projects with a generating capacity of 20 megawatts or less that generate electricity utilizing a type of energy described in ORS 469A.025; or
> >
> > (b) Facilities that generate electricity using biomass that also generate thermal energy for a secondary purpose.
>
> (3) Regardless of the facility's nameplate capacity, any single facility described in subsection (2)(b) of this section may be used to comply with the requirement specified in subsection (2) of this section for up to 20 megawatts of capacity.

The RPS charges the Commission with penalizing electric companies that fail to comply with this requirement. It provides: "If an electric company or electricity service supplier that is subject to a renewable portfolio standard under ORS 469A.005 to 469A.210 fails to comply with the standard in the manner provided by ORS 469A.005 to 469A.210, the Public Utility Commission may impose a penalty against the company or supplier in an amount determined by the commission." ORS 469A.200. The requirement is thus made a part of the other more general RPS requirements, and the Commission is the agency charged with oversight and compliance. We address Staff's specific questions in the order posed by Staff below.

Rulemaking

1. **Should the PUC be engaged in this rulemaking? If not, what other type of process should the commission undertake in order to provide subject utilities with guidelines for compliance?**

CREA-REC Response:

Yes, the Commission should adopt administrative rules. As discussed above, ORS 469A.210 first appeared in the Oregon Revises Statutes in 2007 and has since been amended in 2010, 2016, and 2017. It appears that no rulemaking has ever taken place to ensure that the covered utilities will ever obtain compliance to bring effect to this section, let alone to identify how the Commission will interpret the statutory language for purposes of ensuring compliance.

The Commission should have undertaken this rulemaking and adopted policies promoting the eight-percent requirement when this section was first enacted by the legislature in 2007. The original 2007 statute specifically directed the Commission to "establish policies and procedures promoting the goal" that "at least eight percent of Oregon's retail electrical load comes from small-scale renewable energy projects . . . ." 2007 Oregon Laws, ch 301, § 24. The Commission was repeatedly reminded of, and there were numerous requests that it, adopt such policies and procedures. Despite the legislature's clear and unequivocal direction, the Commission completely ignored this statutory direction in a remarkable abdication of its responsibilities as the most important regulatory agency that could help the state meet this important goal.

Once the goal became a mandate in 2016, the Commission did not move with alacrity, but instead again took no action on community renewables. Finally, in testimony before

Representative Helm and the House Energy and Environment committee at the close of the 2018 legislative session, Commission Staff committed to taking action. CREA and REC understand that certain parties may assert that a rulemaking is not appropriate. However, to fail to open a rulemaking by this time would be an abrogation of the commitments the Commission made to both the legislature and proponents of the community renewables legislation. There should be enforceable rules on the books as soon as possible to ensure compliance will be met on and after the 2025 deadline.

Measurement

2. Should the PUC define how the 8 percent requirement in ORS 469A.210(2) will be measured?

CREA-REC Response:

Yes. The Commission should define how the eight-percent requirement will apply in order to carry out its statutory obligation to implement this provision and enforce violations with penalties.

3. What does electrical capacity mean?

CREA-REC Response:

It is important to define the critical statutory terms correctly. The term "aggregate *electrical* capacity" is used in ORS 469A.210(2) to describe the eight-percent requirement and to measure compliance with the requirement by facilities that meet the statutory criteria, whereas the term "generating capacity" is used in ORS 469A.210(2)(a) to describe qualifying criteria, which is the 20-MW maximum size of facilities qualifying as small-scale. The difference in terms is important given the context.

“Generating capacity” would mean the maximum generating capacity at any instant, i.e., the maximum capacity the facility could potentially *generate* under ideal conditions. If a facility has a generating capacity of 20 MW or less, it can qualify as a facility used by the utility to meet the eight-percent target (assuming it meets the other requirements).

In contrast, the term “electrical capacity” is used for purposes of measuring compliance by determining the numerator (electrical capacity of the facilities used by the utility to meet the requirement) and the denominator (electrical capacity of the utility’s entire generation fleet). The term “electrical capacity” is different from “generating capacity” and should therefore have different meaning. “Electrical capacity” should mean the facility’s ability to contribute electrical capacity to the utility, which is regularly measured in the utility’s integrated resource plan (“IRP”).

At the insistence of the utilities, the Commission has used these types of “electrical capacity” figures for determining the avoided cost rates of different renewable resource types since 2014. *See In Re Public Utility Commission of Oregon: Investigation Into Qualifying Facility Contracting and Pricing*, OPUC Docket No. UM 1610, Order No. 14-058, at 15 (Feb. 24, 2014). It is therefore reasonable to use this measure of electrical capacity for purposes of this statute. While there have been reasonable differences of opinion regarding the precise calculation of capacity contribution of different resource types, the Commission should be capable of utilizing this previous testimony and Commission decisions in response to that testimony in previous proceedings to make that determination for this calculation in a logically consistent manner without undue complexity or administrative burden.

Each electric company's "aggregate electrical capacity" would be the sum of this measurement for all generating facilities owned or under long-term contract of the utility, and eight percent of such aggregate electrical capacity must come from facilities with "generating capacity" of 20 MW or less and otherwise meeting the requirements of ORS 469A.210. Had the legislature intended for the eight-percent target to mean that only eight percent of the utility's aggregate *generating* capacity would come from small-scale facilities, it would have used the term *generating* capacity instead of *electrical* capacity in the clauses of the statute that establish the eight-percent compliance target.

For example, in the case of PacifiCorp, the 2017 IRP lists the capacity contribution to summer peak for PacifiCorp's existing resources in Table 5.2, which includes 5,919 MW of Pulverized Coal, 2,377 MW of Gas-CCCT, 357 MW of Gas-Other, 958 MW of Hydroelectric, 426 MW of DSM, 294 MW of Renewables, 705 MW of Qualifying Facilities – Renewables, 267 MW of Purchases (not hydroelectric, renewables, or natural gas), 146 MW of Qualifying Facilities (non-Renewable), and 195 MW of Interruptible Contracts – for a total capacity contribution at summer peak of 11,645 MW. Assuming this includes all relevant resources, this number would appear to be the denominator in the equation used to determine compliance with the eight-percent requirement, meaning the eight-percent requirement would be small-scale community-based facilities with equivalent capacity contribution to peak of 931.6 MW.[2] The maximum generating capacity of these resources is much larger, but several resource types contribute less than their maximum generating capacity to the electrical capacity needs of PacifiCorp, which is demonstrated in Tables 5.3, 5.4, 5.5, 5.6, 5.7, 5.9, and 5.10, where

2 11,645 MW x 0.08 = 931.6 MW

PacifiCorp shows the maximum generating capacity of the various plants by resource type and the capacity contribution of each plant. Those tables are attached hereto for reference.

Generally speaking, the utility's coal and gas-fired plants will have capacity contribution that is equal to the plant's maximum generating capacity, whereas a renewable plant (such as wind or solar) will have a capacity contribution that is some fraction of its maximum generating capacity. In the 2017 IRP, PacifiCorp explained, "The capacity contribution of wind and solar resources, represented as a percentage of resource capacity, is a measure of the ability for these resources to reliably meet demand. For purposes of the 2017 IRP, PacifiCorp defines the peak capacity contribution of wind and solar resources as the availability among hours with the highest loss of load probability." *PacifiCorp 2017 IRP* at 87. For generating facilities in its west balancing authority, PacifiCorp estimated the capacity contribution of wind facilities to be 11.8 percent of maximum generating capacity, the capacity contribution of fixed tilt solar facilities to be 53.9 percent, and the capacity contribution of tracking solar facilities to be 64.8 percent. *Id.* at 88. Thus, in the case of wind and solar facilities qualifying as small-scale community-based facilities, these values could be used to calculate the numerator of the equation to evaluate compliance with ORS 469A.210, by reducing the maximum generating capacity of the individual facilities by the applicable capacity contribution percentage.

In the case of qualifying hydropower and other baseload renewable facilities, PacifiCorp would assume 100 percent capacity contribution as it does in its IRP and its avoided cost calculations. This is reasonable because baseload resources generally have higher capacity factors that are more in line with thermal generation. Additionally, there are and will be fewer small-scale community-based hydropower and baseload resources over time, and it is more controversial and administratively difficult to determine accurate numbers.

To illustrate further with a simplified example, if PacifiCorp were to meet the entire eight-percent compliance requirement with small-scale community-based solar facilities located in Oregon that used tracking solar, the following equations would evaluate the amount of maximum generating capacity of such facilities needed to meet the requirement:

Eight Percent Aggregate Electrical Capacity = 931.6 MW

(11,645 MW x 0.08 = 931.6 MW)

Generating Capacity Needed = 931.6 MW x (100/64.8)

= 1,437.65 MW of tracking solar

As can be seen, PacifiCorp would need an overall maximum generating capacity of 1,437.65 MW of tracking solar facilities that meet the small-scale community-based criteria, which are discussed further below in response to subsequent questions from Staff.

For purposes of implementing the statutory definitions and compliance requirement in this rulemaking, CREA and REC recommend that the Commission develop an "electrical capacity" percentage that would apply for different resource types used for compliance (numerator) and making up the utility's generation fleet (denominator) to be standardized in the administrative rules for each covered electric company, which currently includes only PacifiCorp and Portland General Electric Company ("PGE"). Because the two utilities may have different peak capacity needs, the rules would provide a different standardized figure for each resource type for each utility.

CREA and REC strongly support using specific numbers in administrative rules, rather than frequent updates. First, using a standardized figure for each company available in the administrative rules (as opposed to a new figure in each IRP cycle) will provide more predictability as to the compliance requirement and will prevent gaming of the measurement in the IRPs and other proceedings. Second, the IRP process can be controversial, and there is no real opportunity to review, challenge or obtain a Commission decision on specific IRP inputs like the capacity contribution of variable generation resources. Here, PacifiCorp and PGE have a vested interest in obtaining a specific number, and they should not be trusted to unilaterally set whether they are in compliance with the small-scale community-based renewable mandate. CREA and REC's position may change in the future if the Commission changes its IRP process if the Commission allows litigation on inputs and assumptions.

4. What does aggregate electrical capacity mean?

CREA-REC Response:

See the prior response. Separately, "aggregate" requires the combined numbers of PacifiCorp and PGE to get an aggregate value for the state's electric companies covered by the overall eight-percent requirement. For implementation purposes, an individual determination and requirement needs to be made for each of these two utilities respectively to meet its proportional contribution to the overall requirement.

5. How should an individual project's capacity be measured?

CREA-REC Response:

As noted above, the "electrical capacity" of the facilities should be used to determine the overall compliance target amount of capacity by measuring peak capacity value to the utility. In contrast, to qualify as a facility used to meet the eight-percent target, the facility must have a "generating capacity" of 20 MW or less, and it might have a much smaller "electrical capacity" used for purposes of its contribution to the utility's compliance target, depending on the resource type.

<u>Project Eligibility</u>

6. Should the PUC determine which projects are eligible to count towards the 8 percent requirement?

CREA-REC Response:

Yes. As noted above, the Commission is the agency charged with ensuring compliance and enforcing violations with penalties, as with other more general RPS requirements. The Commission should require the utilities to begin accounting for this requirement in an open, transparent proceeding as part of the RPS Implementation Plans and compliance filings. Stakeholders should have the opportunity to challenge the utility's calculations and assumptions and recommend further actions the utility and the Commission should take to ensure compliance.

7. What process should the PUC follow to determine which projects are eligible?

CREA-REC Response:

CREA and REC recommend that the existing RPS Implementation Plan and RPS Compliance filing procedures should be revised to require inclusion of compliance with ORS 469A.210 for PacifiCorp and PGE.

8. **Which renewable projects should be eligible?**

CREA-REC Response:

The statute provides that the resources that qualify are resources that meet the general RPS requirements in ORS 469A.025. Additionally, the resource must meet the other specifications in ORS 469A.210, which include that the facilities are "community based" and have a generating capacity of no more than 20 MW except in the case of certain biomass cogeneration facilities that may use up to 20 MW of a facility exceeding that generating capacity.

a. **Can eligible resources be utility-owned?**

CREA-REC Response:

No. Although the statute does not define "community based," the common understanding of that term does not allow for a utility to own and rate base the resources qualifying under ORS 469A.210. In addition, CREA and REC understand that there are already relatively few utility-owned biomass projects or other renewable projects under 20 MW. The statutory requirement was not intended to allow utilities to expand into ownership of smaller projects, but instead were intended to provide an opportunity for non-utility owned projects to be able to sell their power.

b. **Does a utility need to demonstrate a contract length beyond 2025?**

CREA-REC Response:

Yes, with a discrete exception. ORS 469A.210 creates a continuing obligation after the first compliance year where penalties may apply beginning in 2025, and it provides no provisions allowing for banking of the renewable energy certificates supplied to meet the requirement. Thus, if the contract for the utility's purchase of bundled renewable energy certificates and energy of a particular small-scale community-based facility does not extend beyond 2025, the utility would need obtain additional complying resources to comply with eight-percent target in order to comply in a future compliance year. The only exception should be for projects currently selling their power to the electric company and that the electric company assumes will keep selling power to the utility in its integrated resource plan. If the utility is planning on the project renewing its contract, then it should be able to assume that project will be available to meet its community renewables mandate, and the utility would not need to plan to acquire a replacement resource to meet the ongoing compliance mandate in future years.

c. Do existing PURPA projects under 20 MW qualify?

CREA-REC Response:

Yes, an existing PURPA project qualifies if it is as an RPS resource under ORS 469A.025, is located in Oregon, and sells its bundled renewable energy certificates and energy the utility in the compliance year in question.

d. Do community solar projects qualify?

CREA-REC Response:

Yes, a community solar project qualifies if it is as an RPS resource under ORS 469A.025, is located in Oregon, and sells its bundled renewable energy certificates and energy the utility in the compliance year in question. However, as noted above, the community solar resource could not qualify if it were utility owned.

e. Do net-metered projects qualify? (Including the gross portion?)

CREA-REC Response:

No. A net metering facility is not the type of utility-scale generation selling its entire net output to the utility that is envisioned as a qualifying project in ORS 469A.210. Instead, it is an individually owned facility that essentially serves the electrical needs of a single customer by offsetting that customer's usage over the year. Additionally, under Oregon law, the customer owns the renewable energy certificates created by its net metering system, and therefore the electric company could not use those renewable energy certificates to meet the requirement in ORS 469A.210. *See* OAR 860-022-0075.

9. What locational restrictions are applicable?

CREA-REC Response:

The facilities should be located in Oregon. The express purpose of ORS 469A.210 is to meet the legislative finding that small-scale community-based facilities are "an essential element of this state's energy future." ORS 469A.210(1). Given this context, an electric company operating in Oregon cannot meet the legislative objective through the use of facilities located in another state or region.

a. How should PacifiCorp's multi-state service territory be addressed?

CREA-REC Response:

While the statutory requirement may only be met by generating facilities located in Oregon, the eight-percent compliance target must be developed by calculating eight percent of the "electrical capacity" of PacifiCorp's entire multi-state generation fleet. The statute uses the language "eight percent of the aggregate electrical capacity of all electric companies . . . . " ORS

469A.210(2). In turn, the term "electric company" means "an entity engaged in the business of distributing electricity to retail electricity consumers in this state . . . ." ORS 757.600(11); *see also* ORS 469A.005(8) (adopting ORS 757.600(11) for purposes of definition of "electric company" as used in ORS 469A.210). There is no limitation in the statute suggesting that PacifiCorp's compliance target is limited to eight percent of some subset of its generation fleet located within Oregon.

In contrast, the general compliance targets of the RPS in ORS 469A.052 derive their annual compliance percentage from the quantity of "electricity sold by the electric utility to retail electricity consumers in each of the calendar years." *See* ORS 469A.052. Thus, through the definition of "retail electricity consumer" in ORS 469A.005(13), the general RPS compliance requirements limit their annual target to a percentage of such sales to customers "located in Oregon." ORS 469A.005(13). The different use of terms and words in ORS 469A.210 is significant and supports the conclusion that the legislature intended the eight-percent compliance target to be measured by the multi-state utility's entire generation fleet, not the just the fleet located in Oregon or sold to retail electricity customers in Oregon.

10. Does a utility need to own the associated renewable energy certificates of a qualifying project?

CREA-REC Response:

Yes. Oregon's RPS requires that the electric company meet the requirement by retiring the renewable energy certificates supplied to the electric company with bundled energy from such facilities within the compliance year. The law expressly references the requirement in ORS 469A.210 when discussing the limitations on use of renewable energy certificates for other purposes For example, the RPS states, "An electric utility or electricity service supplier that uses a renewable energy certificate to comply with a renewable portfolio standard imposed by a state other than this state may not use the same renewable energy certificate to comply with a renewable portfolio standard established under ORS 469A.005 to 469A.210." ORS 469A.140(5). If the utility could claim compliance without retiring the RECs produced from the facility, there would also be a double counting violation of Federal Trade Commission regulations regarding environmental claims.

Compliance

11. Should the PUC determine compliance with the 8 percent mandate?

CREA-REC Response:

Yes. The utility should have to retire bundled renewable energy certificates generated in the compliance year equal that utility's proportional eight-percent target developed in the administrative rules for each compliance year. Banking is not provided as an option under ORS 469A.210. As noted above, the statute requires the Commission to enforce violations with penalties.

12. When does compliance occur?

CREA-REC Response:

At time of RPS compliance report each year, the utility must demonstrate to the Commission that it has acquired the requisite renewable energy certificates from a sufficient number of facilities to comply with the target, and thereafter the Commission would direct that the utility retire those renewable energy certificates along with the renewable energy certificates retired to meet the other RPS requirements.

13. How should the utility report progress?

CREA-REC Response:

The utility would report compliance in its RPS Compliance Report beginning for compliance year 2025. Beginning at the current time, the Commission should direct the utilities to address how they will obtain compliance in all RPS Implementation Plans and IRPs.

14. How should a utility demonstrate compliance?

CREA-REC Response:

See above.

15. What happens after 2025?

CREA-REC Response:

As noted above, ORS 469A.210 is an ongoing obligation and the utilities must be actively engaged to ensure they maintain the eight-percent compliance level over time as they add more generation resources that do not comply (thus increasing the compliance amount of aggregate electrical capacity) and to ensure they replace any expiring contracts with facilities supplying bundled renewable energy certificates in compliance with ORS 469A.210 with new contracts from other complying facilities.

<u>Additional Questions</u>

16. Do you have any other specific issues you would like addressed in this informal stage of this rulemaking that falls within the scope of this rulemaking as opened by the Commission in Order No. 18-322?

CREA-REC Response:

CREA and REC believe that after the administrative rules have finalized the requirements under ORS 469A.210, the Commission should direct the utilities to develop a small-scale renewable proxy plant for use in setting avoided cost rates to ensure compliance with the target. Such a policy would complement the Commission's current renewable rate policies that implement the more general RPS requirements through use of a major renewable resource proxy plant from the IRP.

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Respectfully submitted,

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Attachment 1

Excerpt of PacifiCorp's 2017 Integrated Resource Plan

The 2017 IRP relies on PacifiCorp's December 2016 load forecast. Table 5.1 shows the annual summer coincident peak load stated in megawatts as reported in the capacity load and resource balance, before any load reductions from Class 2 DSM and private generation. The system summer peak load grows at a compounded average annual growth rate (CAAGR) of 0.85 percent over the period 2017 through 2026.

Table 5.1 – Forecasted System Summer Coincident Peak Load in Megawatts, Before Energy Efficiency and Private Generation

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
System	10,164	10,277	10,384	10,486	10,608	10,718	10,804	10,907	11,028	11,049

Existing Resources

On a system coincident basis, PacifiCorp is a summer-peaking utility. For the forecasted 2017 summer coincident peak, PacifiCorp owns or has interests in resources with an expected system summer peak capacity of 11,645 MW. Table 5.2 provides anticipated system summer peak capacity ratings by resource category as reflected in the IRP load and resource balance for 2017. Note that capacity ratings in the following tables provide resource capacity value at the time of system coincident peak, rounded to the nearest megawatt.

Table 5.2 – 2017 Capacity Contribution at System Summer Peak for Existing Resources

Resource Type[1/]	L&R Balance Capacity at System summer peak (MW)[2/]	Percent of Total (%)
Pulverized Coal	5,919	50.8%
Gas-CCCT	2,377	20.4%
Gas-Other	357	3.1%
Hydroelectric	958	8.2%
DSM[3/]	426	3.7%
Renewables	294	2.5%
Qualifying Facilities—Renewables	705	6.1%
Purchase[4/]	267	2.3%
Qualifying Facilities	146	1.3%
Interruptible Contracts	195	1.7%
Total	**11,645**	**100%**

1/ Sales and Non-Owned Reserves are not included.

2/ Represents the capacity available at the time of system summer peak used for preparation of the capacity load and resource balance. For specific definitions by resource type see the section entitled "Load and Resource Balance Components" later in this chapter.

3/ DSM includes existing Class 1 (direct load control) and Class 2 (energy efficiency) programs.

4/ Purchases constitute contracts that do not fall into other categories such as hydroelectric, renewables, and natural gas.

Thermal Plants

Table 5.3 lists PacifiCorp's existing coal-fueled thermal plants and Table 5.4 lists existing natural-gas-fueled plants. The assumed end-of-life dates are used for the 2017 IRP modeling of existing coal resources.

Table 5.3 – Coal-Fueled Plants

Plant	PacifiCorp Percentage Share (%)	State	Assumed End-of-Life Year	L&R Balance Capacity at System summer peak (MW)
Cholla 4	100	AZ	2042	387
Colstrip 3	10	MT	2046	74
Colstrip 4	10	MT	2046	74
Craig 1	19	CO	2034	82
Craig 2	19	CO	2034	82
Dave Johnston 1	100	WY	2027	106
Dave Johnston 2	100	WY	2027	106
Dave Johnston 3	100	WY	2027	220
Dave Johnston 4	100	WY	2027	330
Hayden 1	24	CO	2030	45
Hayden 2	13	CO	2030	33
Hunter 1	94	UT	2042	418
Hunter 2	60	UT	2042	269
Hunter 3	100	UT	2042	471
Huntington 1	100	UT	2036	459
Huntington 2	100	UT	2036	450
Jim Bridger 1	67	WY	2037	354
Jim Bridger 2	67	WY	2037	359
Jim Bridger 3	67	WY	2037	345
Jim Bridger 4	67	WY	2037	350
Naughton 1	100	WY	2029	156
Naughton 2	100	WY	2029	201
Naughton 3[1/]	100	WY	2029	280
Wyodak	80	WY	2039	268
TOTAL – Coal				**5,919**

[1/] Naughton Unit 3 may be retired at the end of 2018.

Table 5.4 – Natural-Gas-Fueled Plants

Plant	PacifiCorp Percentage Share (%)	State	Assumed End-of-Life Year	L&R Balance Capacity at System summer peak (MW)
Chehalis	100	WA	2043	464
Currant Creek	100	UT	2045	533
Gadsby 1	100	UT	2032	64
Gadsby 2	100	UT	2032	69
Gadsby 3	100	UT	2032	105
Gadsby 4	100	UT	2032	40
Gadsby 5	100	UT	2032	40
Gadsby 6	100	UT	2032	40
Hermiston (owned)	50	OR	2036	227
Lake Side	100	UT	2047	530
Lake Side 2	100	UT	2054	623
TOTAL – Gas and Combined Heat & Power				**2,734**

Renewable Resources

Wind

PacifiCorp either owns or purchases under contract 2,333 MW of wind resources. Since the 2015 IRP Update, the Company has entered into power purchase agreements totaling 40 MW.

Table 5.5 shows existing wind facilities owned by PacifiCorp, while Table 5.6 shows existing wind power purchase agreements.

Table 5.5 – Owned Wind Resources

Wind Project	State	Capacity (MW)	L&R Balance Capacity at System summer peak (MW)
Foote Creek I[1/]	WY	32	6
Leaning Juniper	OR	101	12
Goodnoe Hills Wind	WA	94	11
Marengo	WA	140	17
Marengo II	WA	70	8
Glenrock Wind I	WY	99	16
Glenrock Wind III	WY	39	6
Rolling Hills Wind	WY	99	16
Seven Mile Hill Wind	WY	99	16
Seven Mile Hill Wind II	WY	20	3
High Plains	WY	99	16
McFadden Ridge 1	WY	29	4
Dunlap 1	WY	111	18
TOTAL – Owned Wind		**1,032**	**148**

[1/] PacifiCorp's share is 32 MW of the 40 MW project.

Table 5.6 – Non-Owned Wind Resources

Power Purchase Agreements/Exchanges	State	PPA or QF	Capacity (MW)	L&R Balance Capacity at System Summer Peak (MW)
Combine Hills	OR	PPA	41	5
Foote Creek IV	WY	PPA	17	3
Rock River I	WY	PPA	50	8
Stateline Wind	OR/WA	PPA	175	21
Three Buttes Wind Power (Duke)	WY	PPA	99	16
Top of the World	WY	PPA	200	32
Wolverine Creek	ID	PPA	65	10
Casper Wind (Chevron)	WY	QF	17	3
Chopin	WA	QF	10	1
Foote Creek II	WY	QF	2	0
Foote Creek III	WY	QF	25	4
Latigo Wind	UT	QF	60	9
Mariah Wind	OR	QF	10	1
Meadow Creek Project – Five Pine	ID	QF	40	6
Meadow Creek Project – North Point	ID	QF	80	13
Mountain Wind Power I	WY	QF	61	10
Mountain Wind Power II	WY	QF	80	13
Orchard Wind[1/]	WA	QF	40	5
Oregon Wind Farms I & II	OR	QF	65	8
Orem Family Wind	OR	QF	10	1
Pioneer Wind Park I	WY	QF	80	13
Power County Wind Park North	ID	QF	23	4
Power County Wind Park South	ID	QF	23	4
Spanish Fork Wind Park 2	UT	QF	19	3
Three Mile Canyon	WA	QF	10	1
Small QF	WY	QF	0.2	0
TOTAL – Purchased Wind			**1301**	**191**

[1/] New since 2015 IRP Update

Solar

PacifiCorp has a total of 54 solar projects under contract representing 1,164 MW of nameplate capacity. Of these, two projects totaling 100 MW are new since the 2015 IRP Update.

Table 5.7 – Non-Owned Solar Resources

Power Purchase Agreements/Exchanges	PPA or QF	State	Capacity (MW)	L&R Balance Capacity at System Summer Peak (MW)
Black Cap	PPA	OR	2	1
Utah Solar PV Program	PPA	UT	2	1
Old Mill	PPA	OR	5	3
Oregon Solar Incentive Projects	PPA	OR	10	5
Small Solar	QF	UT	0.5	0
Adams Solar Center	QF	OR	10	6
Bear Creek Solar Center	QF	OR	10	6
Beatty Solar	QF	OR	5	3
Beryl Solar	QF	UT	3	1
Black Cap Solar II	QF	OR	8	5
Bly Solar Center	QF	OR	9	6
Buckhorn Solar	QF	UT	3	1
Cedar Valley Solar	QF	UT	3	1
Chiloquin Solar	QF	OR	10	5
Collier Solar	QF	OR	10	6
Elbe Solar Center	QF	OR	10	6
Enterprise Solar	QF	UT	80	47
Escalante Solar I	QF	UT	80	47
Escalante Solar II	QF	UT	80	47
Escalante Solar III	QF	UT	80	47
Ewauna Solar	QF	OR	1	1
Ewauna Solar 2	QF	OR	3	2
Fiddler's Canyon Solar 1-3	QF	UT	9	5
Granite Mountain – East	QF	UT	80	47
Granite Mountain – West	QF	UT	50	30
Granite Peak Solar	QF	UT	3	1
Greenville Solar	QF	UT	2	1
Iron Springs	QF	UT	80	47
Ivory Pine Solar	QF	OR	10	6
Laho Solar	QF	UT	3	1
Merrill Solar	QF	OR	10	6
Milford Flat Solar	QF	UT	3	2
Milford Solar 2	QF	UT	3	1
Norwest Energy 2 (Neff)	QF	OR	10	6
Norwest Energy 4 (Bonanza)	QF	OR	6	4
Norwest Energy 7 (Eagle Point)	QF	OR	10	6
Norwest Energy 9 Pendleton	QF	OR	6	3
OR Solar 2, LLC (Agate Bay)	QF	OR	10	6
OR Solar 3, LLC (Turkey Hill)	QF	OR	10	6
OR Solar 5, LLC (Merrill)	QF	OR	8	5
OR Solar 6, LLC (Lakeview)	QF	OR	10	6
OR Solar 7, LLC (Jacksonville)	QF	OR	10	6
OR Solar 8, LLC (Dairy)	QF	OR	10	6
Pavant Solar	QF	UT	50	29
Pavant Solar II LLC	QF	UT	50	30
Pavant Solar III LLC[1/]	QF	UT	20	12
Quichapa Solar 1-3	QF	UT	9	5
South Milford Solar	QF	UT	3	2
Sprague River Solar	QF	OR	7	5
Sweetwater Solar[1/]	QF	WY	80	48
Three Peaks Solar	QF	UT	80	47
Tumbleweed Solar	QF	OR	10	5
Utah Red Hills Renewable Park	QF	UT	80	47
Woodline Solar	QF	OR	8	5
TOTAL – Purchased Solar			**1,164**	**690**

[1/] New since 2015 IRP Update

Geothermal

PacifiCorp owns and operates the Blundell geothermal plant in Utah, which uses naturally created steam to generate electricity. The plant has a net generation capacity of 34 MW. Blundell is a fully renewable, zero-discharge facility. The bottoming cycle, which increased the output by 11 MW, was completed at the end of 2007. The Oregon Institute of Technology added a new small qualifying facility (QF) using geothermal technologies to produce renewable power for the campus that is rated at 0.28 MW. PacifiCorp has a six-year power purchase agreement with a 3.65 MW QF geothermal project near Lakeview, Oregon, which became operational September 2016.

Biomass/Biogas

PacifiCorp has biomass/biogas agreements with 19 projects totaling approximately 100 MW of nameplate capacity. At least one project is located in each state in PacifiCorp's service territory.

Renewables Net Metering

Installation rates for net metering facilities have been relatively consistent for the last few years over most of PacifiCorp's service territory. Utah, however, has seen tremendous growth—an approximate 180 percent increase year over year—in the amount of residential solar being interconnected. Table 5.8 provides a breakdown of net metered capacity and customer counts from data collected on November 30, 2016.

Table 5.8 – Net Metering Customers and Capacities

Fuel	Solar	Wind	Gas[1/]	Hydro	Mixed[2/]
Nameplate (kW)	184,548.20	793.66	884	658.40	1130.11
Capacity (percentage)	98.16%	0.42%	0.47%	0.35%	0.60%
Number of customers	22,355	198	4	14	60
Customer (percentage)	98.78%	0.87%	0.02%	0.06%	0.27%

[1/] Gas includes: biofuel, waste gas, and fuel cells
[2/] Mixed includes projects with multiple technologies, one project is solar and biogas and the others are solar and wind

Hydroelectric Generation

PacifiCorp owns 1,135 MW of hydroelectric generation capacity and purchases the output from 127 MW of other hydroelectric resources.[1] These resources provide operational benefits such as flexible generation, spinning reserves and voltage control. PacifiCorp-owned hydroelectric plants are located in California, Idaho, Montana, Oregon, Washington, Wyoming, and Utah.

The amount of electricity PacifiCorp is able to generate or purchase from hydroelectric plants is dependent upon a number of factors, including the water content of snow pack accumulations in the mountains upstream of its hydroelectric facilities and the amount of precipitation that falls in

[1] PacifiCorp's 2016 10-K shows 1,135 MW of Net Facility Capacity.

its watershed. Operational limitations of the hydroelectric facilities are affected by varying water levels, licensing requirements for fish and aquatic habitat, and flood control, which lead to load and resource balance capacity values that are different from net facility capacity ratings.

Hydroelectric purchases are categorized into two groups, as shown in Table 5.9, which shows 2017 capacity included in the load and resource balance.

Table 5.9 – Hydroelectric Contracts - Load and Resource Balance Capacities

Hydroelectric Contracts by Load and Resource Balance Category	L&R Balance Capacity at System summer peak (MW)
Hydroelectric	89
Qualifying Facilities—Hydroelectric	38
Total Contracted Hydroelectric Resources	**127**

Table 5.10 provides the operational capacity for each of PacifiCorp's owned hydroelectric generation facilities at system summer peak (2017).

Table 5.10 – PacifiCorp Owned Hydroelectric Generation Facilities – Load and Resource Balance Capacities

Plant	State(s)	L&R Balance Capacity at System summer peak (MW)
West		
Big Fork	MT	4
Klamath – Dispatch	CA	56
Klamath – Flat	CA	11
Klamath – Shape	OR	86
Lewis – Dispatch	WA	390
Lewis – Shape[1/]	WA	94
Rogue	OR	31
Small West Hydro[2/]	CA/OR/WA	2
Umpqua – Flat	OR	24
Umpqua – Shape	OR	89
East		
Bear River – Dispatch	ID/UT	53
Bear River – Shape	ID/UT	16
Small East Hydro[3/]	ID/UT/WY	14
TOTAL – Hydroelectric before Contracts		**869**
Plus Hydroelectric Contracts		**127**
TOTAL – Hydroelectric with Contracts		**996**

1/ Cowlitz County PUD owns Swift No. 2, and is operated in coordination with the other projects by PacifiCorp
2/ Includes Bend, Fall Creek, and Wallowa Falls
3/ Includes Ashton, Paris, Pioneer, Weber, Stairs, Granite, Snake Creek, Olmstead, Fountain Green, Veyo, Sand Cove, Viva Naughton, and Gunlock

Hydroelectric Relicensing Impacts on Generation

Table 5.11 lists the estimated impacts to average annual hydro generation from expected Federal Energy Regulatory Commission (FERC) orders and relicensing settlement commitments. PacifiCorp assumes that the Klamath hydroelectric facilities will be decommissioned in accordance with the Klamath Hydroelectric Settlement Agreement in the year 2020 and that other projects currently in relicensing will receive new operating licenses, but that additional

Pages Omitted

Load and Resource Balance Components

The capacity and energy balances make use of the same load and resource components in their calculations. The main component categories consist of the following: resources, obligation, reserves, position, and available FOTs.

Under the calculations, there are negative values in the table in both the resource and obligation sections. This is consistent with how resource categories are represented in portfolio modeling. The resource categories include resources by type—thermal, hydroelectric, renewable, QFs, purchases, existing Class 1 DSM, sales, and non-owned reserves. Categories in the obligation section include load (net of private generation), interruptible contracts, existing Class 2 DSM, and new Class 2 DSM from the preferred portfolio.

Existing Resources
A description of each of the resource categories follows:

Thermal
This category includes all thermal plants that are wholly owned or partially owned by PacifiCorp. The capacity balance counts them at maximum dependable capability at time of system summer or winter peak, as applicable. The energy balance also counts them at maximum dependable capability, but de-rates them for forced outages and maintenance. This includes the existing fleet of coal-fueled units, six natural-gas-fueled plants, and one cogeneration unit. These thermal resources account for roughly two-thirds of the firm capacity available in the PacifiCorp system.

Hydroelectric
This category includes all hydroelectric generation resources operated in the PacifiCorp system, as well as a number of contracts providing capacity and energy from various counterparties. The capacity balance counts these resources by the maximum capability that is sustainable for one hour at the time of system summer peak, an approach consistent with current Western Electric Coordinating Council (WECC) capacity reporting practices. The energy associated with stream flow is estimated and shaped by the hydroelectric dispatch from the Vista Decision Support System model. Also accounted for are energy impacts of hydro relicensing requirements, such as higher bypass flows that reduce generation. Over 90 percent of the hydroelectric capacity is on the west side of the PacifiCorp system.

Renewable
This category comprises geothermal and variable (wind and solar) renewable energy capacity. The capacity balance counts the geothermal plant by the maximum dependable capability while the energy balance counts the maximum dependable capability after forced outages. The capacity contribution of wind and solar resources, represented as a percentage of resource capacity, is a measure of the ability for these resources to reliably meet demand. For purposes of the 2017 IRP, PacifiCorp defines the peak capacity contribution of wind and solar resources as the availability among hours with the highest loss of load probability. PacifiCorp updated its capacity contribution values for solar and wind resources, differentiated by resource type and balancing authority area, which is presented in Volume II, Appendix N (Wind and Solar Capacity Contribution Study). The resulting capacity contribution values are shown in Table 5.13 below.

Table 5.13 Summer Peak Capacity Contribution Values for Wind and Solar

	East Balancing Authority Area			West Balancing Authority Area		
	Wind	Fixed Tilt Solar PV	Single Axis Tracking Solar PV	Wind	Fixed Tilt Solar PV	Single Axis Tracking Solar PV
Capacity Contribution Percentage	15.8%	37.9%	59.7%	11.8%	53.9%	64.8%

Purchase

This includes all major purchases contracts for firm capacity and energy in the PacifiCorp system.[4] The capacity balance counts these by the maximum contract availability at time of system summer peak. The energy balance counts contracts at optimal economic model dispatch. Purchases are considered firm and thus planning reserves are not held for them.

Qualifying Facilities (QF)

All QFs that provide capacity and energy are included in this category. Like other power purchases, the capacity balance counts them at maximum system summer peak availability and the energy balance counts them at optimal economic model dispatch.

Dispatchable Load Control (Class 1 DSM)

Existing dispatchable load control program capacity is categorized as an increase to resource capacity. This is in line with the treatment of DSM capacity in the latest version of the System Optimizer model that PacifiCorp uses to select resources.

Sales

This includes all contracts for the sale of firm capacity and energy. The capacity balance counts these contracts by the maximum obligation at time of system summer peak and the energy balance counts them by expected model dispatch. All sales contracts are firm and thus planning reserves are held for them in the capacity view.

Non-owned Reserves

Non-owned reserve capacity is categorized as a decrease to resource capacity to represent the capacity required to provide reserves as a balancing are authority for load and generation that are in PacifiCorp's balancing authority area (BAA) but not owned by PacifiCorp's. There are a number of counterparties that operate in the PacifiCorp control areas that purchase operating reserves. The annual reserve obligation is about 3 MW and 38 MW on the west and east BAAs, respectively. The non-owned reserves do not contribute to the energy obligation because the requirement is for capacity only.

Obligation

The obligation is the total electricity demand that PacifiCorp must serve, consisting of forecasted retail load less private generation, existing Class 2 DSM, new Class 2 DSM from the preferred portfolio, and interruptible contracts. The following are descriptions of each of these components:

[4] PacifiCorp has curtailment contracts for approximately 172 MW on peak capacity that are treated as firm purchases. PacifiCorp has the right to curtail the customer's load as needed for economic purposes. The customer in turn may or may not pay market-based rates for energy used during a curtailment period.