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May 12, 2017

Via Electronic Filing

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
Salem OR 97301

Re: In the Matter of PORTLAND GENERAL ELECTRIC CO.
2016 Integrated Resource Plan
Docket No. LC 66

Dear Filing Center:

Please find enclosed the redacted version of the Final Comments of the Industrial Customers of Northwest Utilities ("ICNU") in the above-referenced docket. Also enclosed are the Final Comments of Bradley G. Mullins on behalf of ICNU.

The confidential portion of ICNU's comments is being handled pursuant to Order No. 16-408 and will follow to the Commission via Federal Express.

Thank you for your assistance. If you have any questions, please do not hesitate to call.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

Enclosures

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the confidential portion of the **Final Comments of the Industrial Customers of Northwest Utilities** upon the parties shown below by mailing a copy via First Class U.S. Mail, postage prepaid, or via hand-delivery.

Dated at Portland, Oregon, this 12th day of May, 2017

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 66

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY 2016 Integrated Resource Plan.	)))))))	FINAL COMMENTS OF THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

I. INTRODUCTION

Pursuant to the Administrative Law Judge's March 2, 2016 Ruling, the Industrial Customers of Northwest Utilities ("ICNU") files these Final Comments on Portland General Electric Company's ("PGE" or the "Company") 2016 Integrated Resource Plan ("IRP").

The Oregon Public Utility Commission ("Commission") requires utilities to propose "a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers."[1/] PGE's Action Plan fails this threshold requirement.

The Company continues to propose acquiring a major new resource that complies with the state's renewable portfolio standard ("RPS") well before it is needed, but has failed even to acknowledge the risks associated with this strategy, let alone analyze them. That PGE may be able to defer the in-service date of this resource until 2020 and still capture the full value of the

[1/] Docket No. UM 1056, Order No. 07-002, Appen. A at 1-2 (IRP Guideline 1c) (Jan. 8, 2007).

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production tax credit ("PTC") is immaterial because the Company's need for this resource has correspondingly been pushed out to at least 2029, and likely further.

As demonstrated in the companion comments of Bradley G. Mullins, the Company's analysis of net present value revenue requirement ("NPVRR") benefits from early action to capture the PTC continues to be flawed. But even assuming the Company's analysis is accurate, the minimal savings customers could realize under the most optimistic scenario does not justify the risks inherent in acquiring a resource a decade or more before it is needed. The annual levelized cost savings from the Company's proposal amounts to less than one percent of current revenue requirement. This is assuming customers can be considered to "save" anything at all. Current customers, in fact, will incur a cost, not experience a savings, from paying for a resource they do not need. The Company's proposal, in other words, is a textbook example of intergenerational inequity and shoves massive risk onto customers. Moreover, acquiring a near-term RPS resource will have harmful ancillary effects by artificially inflating the Company's avoided cost rates for renewable qualifying facilities ("QFs"). These excess avoided cost rates will offset whatever benefits may exist from early action. PGE's RPS Action Plan is patently unreasonable, even using the Company's own assumptions. The Commission should not acknowledge it.

While it does appear that the Company is likely to have a capacity need in 2021, the amount of this need remains in doubt and is highly dependent on PGE's market access, which the Company has not adequately addressed. The Company has also failed to demonstrate that, to the extent it has a capacity deficit, this deficit should be met with "dispatchable capacity."

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ICNU, therefore, recommends that the Commission:

- Decline to acknowledge PGE's Action Plan item to acquire a new RPS-compliant resource on the grounds that the Company has not demonstrated this to be a reasonable action that will lead to the best combination of costs and risks for customers; and

- Decline to acknowledge PGE's Action Plan to issue an RFP for flexible capacity until the Company can demonstrate the extent to which it can rely on the market to meet its capacity needs, and can demonstrate that any need it does have must be met with "dispatchable," as opposed to other sources of, capacity.

II. DISCUSSION

PGE seeks acknowledgement of its Action Plan under the Commission's IRP guidelines. Acknowledgement signifies that a plan is "reasonable based on information available at that time."[2/] This includes a determination of "whether the utility has proposed a portfolio of resources to meet its energy demand that presents the best combination of cost and risk."[3/]

While acknowledgement is the goal, it is "not the required outcome."[4/] Moreover, the Commission need not acknowledge the Action Plan as a whole, and can "decline to acknowledge specific action items if we question whether the utility's proposed resource decision presents the least cost and risk option for its customers."[5/]

The Commission has repeatedly made clear that IRP acknowledgement does not guarantee favorable subsequent ratemaking treatment.[6/] Nevertheless, there is no question that acknowledgement of an action plan item assists the utility in a subsequent prudence review in a ratemaking proceeding: "Consistency of resource investments with least-cost planning

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2/ Re PGE 2013 IRP, Docket No. LC 56, Order No. 14-415 at 1 (Dec. 2, 2014).
3/ Id. at 2.
4/ Order No. 07-002 at 25.
5/ Order No. 14-415 at 1.
6/ See, e.g., Order 89-507 at 6-7; Order No. 07-002 at 24-25; Order No. 14-415 at 2.

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principles will be an additional factor that the Commission will consider in judging prudence …. Consistency with the plan may be evidence in support of favorable rate-making treatment ….”[7/]

A. PGE's RPS Action Plan does not provide customers with the best combination of cost and risk, even under the Company's own assumptions, and will result in unnecessarily high avoided cost rates for QFs.

The Company has failed to justify its Action Plan to acquire new renewable resources. It is crucial to understand that this is an economic action item – PGE does not need a new resource for RPS compliance. Rather, it bases its proposal on the position that early action is cheaper than waiting.[8/] According to the Company, acquiring a new RPS resource by 2020 to capture the PTC results in a lower net present value revenue requirement ("NPVRR") over the planning horizon than delaying acquisition of a new RPS resource until at least 2029, when it has an actual need for this resource.[9/] Here is the Company's proposal broken into its essential elements:

- Beginning in 2020, customers will pay for a resource whose sole purpose at that time will be to bank RECs for future customers, if they are ever used at all;[10/]
- The "need" for this resource will also inflate these customers' power costs by creating an artificial resource deficiency period that effectively doubles the price PGE pays for power from renewable QFs; and
- In 2030, when the resource may be needed for RPS compliance, the PTC will expire, requiring these customers to pay for the undiscounted cost of a 10-year old wind plant that is sure to be technologically and economically inferior to what PGE could have acquired had it waited.

7/ Order No. 89-507 at 7.

8/ PGE Reply Comments at 16-17.

9/ Id. & Attach. B at 7.

10/ Under SB 1547, the resource PGE proposes to acquire would generate RECs that can be banked indefinitely for the first five years of the resource's life. SB 1547 § 7(3)(c). Under the Company's current methodology, those RECs would be used after limited-life RECs, and older unlimited-life RECs would be used before newer unlimited-life RECs, meaning that RECs generated from PGE's proposed resource would likely stay in the bank for many years. There is no telling what the RPS will look like when these RECs are retired.

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Based on the Company's IRP analysis, one would think that customers benefit from an early-action strategy. Who these customers are, however, remains unclear.

As Mr. Mullins demonstrates, ICNU continues to conclude that early-action is a costlier proposition for customers.[11/] But the essential facts outlined above demonstrate that the Company's own modeling provides the Commission with the evidence it needs to reject PGE's RPS Action Plan.

1. <u>PGE has not adequately evaluated the risks associated with its RPS Action Plan.</u>

PGE proposes to acquire a new RPS-eligible resource to capture the full value of the PTC, which it says is now available through 2020.[12/] Meanwhile, updates to the load forecast and contracts with qualifying facilities ("QFs") executed through December 2016 have pushed its need for such a resource out until 2029.[13/] Consequently, extension of the period in which the 100% PTC may be captured has corresponded with a similar extension of the period in which PGE has no need for a physical resource.

The Company is supposed to select "a portfolio of resources with the best *combination* of expected costs *and* associated *risks* and *uncertainties* for the utility and its customers."[14/] Even if the Commission accepts all of PGE's assumptions and finds that its proposal is least cost over the Company's 34-year planning horizon based on what is known today, the point is that very little is known today about the Company's compliance options and their cost when it will actually need a resource for RPS compliance. As Staff notes, "[e]conomic

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11/ B. Mullins Final Comments at 14.
12/ PGE Reply Comments at 15.
13/ <u>Id.</u> at 16.
14/ Order No. 07-002, Appen. A at 1-2 (IRP Guideline 1c) (emphasis added).

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hedging, in the form of full utilization of PTCs … seem[s] somewhat speculative and may actually result in costs to customers not outweighed by the benefits."[15/] The Company's proposal, Staff continues, "neither would serve an immediate system or regulatory need and rests on speculation that its near-term acquisition would serve as an economic hedge[, which] comes at the expense of ratepayers who may not receive the benefit for a number of years, potentially over a decade."[16/] ICNU agrees with Staff.

So does the Company, at least until recently. In its update to its last IRP, PGE found that relying on its banked RECs for compliance "enables PGE to delay costs of physical compliance in 2020, while using the REC bank as a balancing mechanism to hedge against factors that pose future cost or compliance risks for PGE."[17/] This statement would seem to be only more compelling today as the Company's need for a physical resource has been pushed from 2025, when it made this statement, to at least 2029 currently.[18/]

Moreover, 2029 is likely the earliest date PGE will need a physical resource. Its determination of this date assumes it will purchase no unbundled RECs in the future and maintains its "minimum REC bank,"[19/] which both ICNU and Staff criticized in their opening comments.[20/] Merely eliminating the minimum REC bank pushes the Company's need out beyond 2030.[21/] Assuming the Company purchases unbundled RECs to meet 20% of its compliance obligation pushes the need out to 2034.[22/] And even this is likely understating it. As

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15/ Staff Opening Comments at 17.
16/ Id.
17/ Docket No. LC 56, PGE 2013 IRP Update at 47-48 (Dec. 2, 2015).
18/ Id. at 47, Figure 3-1.
19/ PGE Reply Comments, Attach. B at 7.
20/ Staff Opening Comments at 18-21; ICNU Opening Comments at 11-14.
21/ PGE Reply Comments, Attach. B at 22.
22/ Closing Comments of B. Mullins at 12.

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the Company's recent filing in Docket No. UM 1728 to update its avoided costs indicates, it has been inundated with requests for contracts from QFs, representing over 530 MW in the queue.[23/] If the Company's forecast accounted for contracts it has executed to date, rather than through last December, its need for a physical resource would be pushed out even further.[24/] Moreover, the Company will be physically compliant – meaning that it will not even need to draw on its banked RECs – until 2025.[25/]

The following are some examples of what could happen between now and 2029 (let alone 2034) that would materially impact the economics of the Company's proposal to invest hundreds of millions of dollars on a new RPS resource in the near term:

- The PTC could be reextended;
- There could be material changes to the RPS law;
- Economic transmission capacity from Montana or Wyoming could become available;
- New unforeseen technologies could be developed;
- The Bonneville Power Administration could be fundamentally restructured, which could effect profound changes on Northwest energy markets;[26/]
- PGE could hit the incremental 4% cost cap,[27/] potentially obviating the need for a new RPS resource altogether, a risk that is increasingly likely given the avoided cost rates PGE is currently required to pay renewable QFs.[28/]

[23/] Docket No. UM 1728, PGE Supplemental Application at 1 (May 1, 2017).

[24/] PGE refused to provide information on QF contracts executed after December 2016. See Attachment A at 1 (PGE Resp. to ICNU DR 038).

[25/] PGE Reply Comments at 61 (noting that "PGE's physical RPS position in 2021 may be as high as 21.2% of retail load even without early RPS action"). PGE will have a 20% RPS compliance obligation until 2025, when its obligation will increase to 27%.

[26/] BPA's regional dialogue contracts with its preference power customers expire in 2028. BPA's preference power rates are currently higher than market prices, raising questions about whether these customers will renew their contracts.

[27/] ORS 469A.100(1).

[28/] Infra at 13-15.

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Most, if not all, of these scenarios are essentially impossible to predict. Yet, simultaneously, it is likely that at least one of them, or something else not listed, will occur between now and when the Company actually needs an RPS resource.

Still, PGE continues to proceed along its proposed compliance path by assuming that everything will essentially remain the same as it is today. Natural gas prices may go up or down; load may grow faster or slower; but in 2029 we will apparently still be building intermittent, non-dispatchable RPS resources with middling capacity factors and backing them up with flexible gas plants. The possibility that something other than this scenario may exist over a decade from now is utterly foreign to the Company's IRP.[29/]

The Commission's IRP guidelines state that "[r]isk and uncertainty must be considered."[30/] This is particularly important when the Company is proposing an economic resource decision. If the Commission is going to acknowledge an Action Plan that has nothing to do with meeting PGE's service obligations to its customers and is based entirely on the prospect that this plan will save customers money over the long term, then the Commission at least should be relatively sure that customers will in fact save money. If PGE had an RPS need in 2022, acquiring a resource to meet this need in 2018 or 2020 to capture the PTC might provide sufficient assurance of financial benefits to justify the resource action. But to acquire a resource in the near term with the idea that it will save money over a decade from now is to play a guessing game. Ultimately, it may be PGE itself that said it best:

> A basic tenet in long-term planning is input assumptions become increasingly uncertain the further in the future the assumption is applied. This is true for *all input assumptions* ranging from the

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29/ PGE Reply Comments, Attach. B at 23 (showing only gas price, CO_2, and load sensitivities)

30/ Guideline 1b.

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> variable cost of natural gas to the cost estimates for building new generation resources. Additionally, *predicting particular RPS compliance cost factors*, such as future REC values, with certainty is *impracticable*."[31/]

Regardless of what PGE's financial forecast shows about the cost-effectiveness of near-term RPS action, the Company's proposal raises significant "question[s about] whether the utility's proposed resource decision presents the least cost and risk option for its customers."[32/] On the basis of risk alone, the Company's proposal should not be acknowledged as reasonable.

2. <u>The purported financial benefits of early RPS action do not outweigh the risks and will be inequitably allocated</u>.

If the Company's RPS Action Plan does not deliver on the "risk" side of the equation, it is also questionable on the "cost" side. Mr. Mullins' analysis continues to show that this is a higher-cost strategy for customers.[33/] But even under the Company's modeling, customers could hope to save approximately $16.5 million per year on a nominal levelized basis – less than one percent of the Company's revenue requirement.[34/] That hardly seems to justify the substantial risks that these savings will not actually materialize.

Furthermore, for existing customers, this "cost savings," as PGE terms it,[35/] is illusory. Customer rates are not likely to decline once they are required to pay for a new resource when the alternative is for them not to pay for a resource at all. Existing customers, therefore, will simply pay more in rates to bank RECs that will be used to benefit future

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31/ PGE 2013 IRP Update at 49 (emphasis added).
32/ Order No. 14-415 at 1.
33/ B. Mullins Final Comments at 12.
34/ Based on a revenue requirement of $1.78 billion and projected NPVRR savings from early action of $186.7 million.
35/ PGE Reply Comments at 14.

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customers decades later, indeed if they are ever used.[36] This is not a "cost savings" for current customers – it is a classic violation of intergenerational equity.

The Commission has found that achieving intergenerational equity requires it to:

> [B]alance customers' interests over time …. When determining the period over which utilities will recover the costs of assets incurred to produce future benefits, as well as the period over which customers will receive the benefit of utility cost savings, the Commission attempts to equitably allocate those costs and benefits to customers over time so no one generation of customers receives an inequitable share.[37]

PGE's proposed RPS Action Plan achieves the opposite of this "established ratemaking principle[]."[38] It requires existing customers to pay for a resource from which they will receive little or no benefit.

In short, even under the Company's projections, its RPS Action Plan falls well short of providing customers with the "best combination of cost and risk." The appropriate strategy, as PGE has previously recognized, is to delay physical compliance with the RPS until such compliance is necessary in order to maintain maximum flexibility to adapt to rapidly changing circumstances.[39]

3. <u>Forecasting the purchase of unbundled RECs further delays PGE's physical RPS need, thereby increasing the risk of a near-term acquisition.</u>

As noted above, the speculative nature of financial benefits associated with near-term RPS action is even more egregious when the analysis assumes that PGE can meet 20% of its RPS compliance with unbundled RECs. ICNU continues to disagree with PGE's position on

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[36] <u>Supra</u>, n. 10.
[37] Docket Nos. DR 10, UE 88, UM 989, Order No. 08-487 at 66 (Sept. 30, 2008).
[38] <u>Id.</u>
[39] PGE 2013 IRP Update at 47-48.

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forecasting unbundled REC purchases. The Company's resistance to this suggestion is based on the position that forecasting unbundled REC prices is speculative.[40] This is ironic given the RPS strategy PGE is proposing, where it would put customers on the hook for an enormous capital investment over a decade before it is needed. All assumptions in the IRP are to some extent speculative. That is no excuse to pretend that a compliance instrument that is cheap, available, and being used for compliance today does not exist.[41]

In any event, the speculative nature of unbundled REC prices in 2040 is largely beside the point. What PGE does not address is that, not only does forecasting unbundled REC purchases impact portfolio cost, it also impacts the *timing* of an RPS resource need. The more unbundled RECs PGE purchases, the more bundled RECs it can bank for future years. This further impacts the risk customers would assume under PGE's early action RPS proposal because, as the Company has said, "input assumptions become increasingly uncertain the further in the future the assumption is applied."[42] Thus, if one assumes at least some unbundled REC

40/ PGE Reply Comments at 28-29.

41/ ICNU also disagrees with PGE's contention that the cost of unbundled RECs is likely to increase substantially. The Company essentially makes a supply and demand argument by citing California's and Oregon's 50% RPS obligations by 2030 and 2040, respectively, as reasons why unbundled RECs will become more expensive. As these states approach these mandates, PGE argues, "an assumption of persistently low unbundled REC prices in the West would be highly speculative." PGE Reply Comments at 28. In California, however, the ability of covered entities to comply with unbundled RECs is limited to 10% of these entities' compliance obligation. Cal. Pub. Utils. Code § 399.15(b)(2)(B). The increasing RPS obligations in that state, therefore, should have a relatively minor impact on the demand for unbundled RECs in the WECC. Meanwhile, Oregon has created thermal RECs, which qualify as unbundled RECs in the state. Oregon is the only state in the WECC that currently has thermal RECs, and any facility within the WECC may generate these RECs for Oregon's RPS compliance. ICNU has a number of members, each of which are capable of generating literally millions of thermal RECs. Assuming these RECs are sold into the market, they are likely to ensure a continued heavy supply of unbundled RECs and keep prices low, at least in Oregon.

42/ PGE 2013 IRP Update at 49.

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purchases, PGE's physical RPS need is pushed out beyond 2030 and the purported savings associated with its proposed early action strategy look progressively speculative.

Notably, forecasting at least some unbundled REC purchases would only reflect what is likely to occur anyway. Even if the Company continues to pursue its current strategy of forecasting no unbundled REC purchases, any purchases it does make in actuality will still impact the size and timing of its future RPS resource need. Surely the Company will purchase *some* unbundled RECs going forward. ICNU only asks that the Company recognize this fact in order to provide a more realistic picture of when it will actually need a new RPS resource. Instead, the Company's assessment of the year in which it would need to acquire a new RPS resource is based on precisely the opposite conclusion – that it will purchase not a single unbundled REC in any future year.[43/] Not only is this both extremely unlikely and directly contrary to the Company's RPS compliance activities to date, it is also demonstrably wrong.[44/] As it has done in prior years, PGE has, once again, already purchased all the unbundled RECs it can use for RPS compliance in 2016 and then some.[45/] And once again, it did so at extremely low cost.[46/] The IRP Guidelines state that that "[a]ll known resources for meeting the utility's load should be considered …."[47/] ICNU submits that all known resources for meeting the utility's RPS requirements also should be considered, particularly when they are, in fact, being

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43/ PGE Reply Comments, Attach. B.

44/ Re PGE 2015 RPS Compliance Report, Docket No. UM 1783, Order No. 16-416, Appen. A at 3 (Oct. 25, 2016); Re PGE 2014 RPS Compliance Report, Docket No. UM 1740, Order No. 15-344, Appen. A at 3 (Oct. 20, 2015); Re PGE 2013 RPS Compliance Report, Docket No. UM 1699, Order No. 14-370, Appen. A at 2 (Oct. 28, 2014); Re PGE 2012 RPS Compliance Report, Docket No. UM 1658, Order No. 13-422, Appen. A at 2 (Nov. 12, 2013); *Re PGE 2011 RPS Compliance Report*, Docket No. UM 1605, PGE RPS Compliance Report at 2 (June 1, 2012) (showing 183,063 unbundled RECs used for compliance).

45/ Confidential Attachment A at 3 (PGE Resp. to ICNU DR 039, Conf. Attach. A).

46/ Id.

47/ Guideline 1a.

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used to meet the utility's RPS requirements. As Mr. Mullins demonstrates, the Company has the potential to be RPS resource sufficient until 2034 if it continues to satisfy a portion of its compliance obligation with unbundled RECs.[48/] The Commission should consider this when determining whether a major near-term investment provides customers with the best combination of cost and risk.

4. PGE's RPS Action Plan will unnecessarily increase power costs.

In addition to requiring customers to pay for a resource they do not need based on speculative long-term benefits, the Company's proposal to acquire an RPS resource by 2020 will also harm customers by requiring them to pay more than necessary for power from QFs under the Public Utility Regulatory Policies Act ("PURPA"). The Commission can prevent this from happening even if it declines to acknowledge the Company's RPS Action Plan. While the Commission's rules specify that PGE is to update its avoided costs "within 30 days of Commission *acknowledgement* of its least-cost plan,"[49/] the Commission may still authorize updated avoided costs absent IRP acknowledgement. The Commission has the authority to waive any of its PURPA rules "for good cause shown."[50/] Ensuring that customers pay no more than a utility's true avoided costs not only constitutes good cause, it is the Commission's statutory obligation.[51/] Additionally, the Commission has clarified that "[w]here the utility's IRP and IRP action plan are partially acknowledged, the utility will be directed to offer its own proposal for the demarcation of resource sufficiency and deficiency. Parties will be allowed to

48/ B. Mullins Final Comments at 14.
49/ OAR 860-029-0040(4)(a) (emphasis added).
50/ OAR 860-029-0005(4).
51/ 16 U.S.C. § 824a-3(b) (specifying that rates for QF purchase are not to "exceed" avoided costs); ORS 756.040(1) (requiring the Commission to ensure rates are just and reasonable).

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respond to the utility proposal. The Commission will then make the final determination."[52/] This indicates that IRP acknowledgement is not an essential precursor to updating avoided costs. Conversely, acknowledgement of PGE's RPS Action Plan as proposed in its IRP will result in its resource deficiency period beginning in 2020, forcing customers to pay rates for QF power that do not reflect the Company's true avoided cost. This is not in the public interest.

Under the Commission's rules, a utility is to provide a full update to its avoided costs "within 30 days of Commission acknowledgement of its least-cost plan …."[53/] The Commission has concluded that "the IRP process is the appropriate venue for addressing resource sufficiency/deficiency issues,"[54/] and that the "IRP preferred portfolio and Action Plan provide the basis for deciding when a renewable resource would be avoided by QF purchases."[55/] Consequently, because the Company's Action Plan includes an RPS resource acquisition by 2020, its resource deficiency period will presumably also remain at 2020. As the Company's recent filing in UM 1728 shows, however, even with updated avoided cost rates, customers will pay a wind QF a renewable fixed price of between $50 and $65 per MWh in 2020, rising to over $80/MWh in 2030.[56/] This is in contrast to the $24-$31/MWh price customers will pay these same QFs in 2019, when PGE is resource sufficient.[57/] It is not difficult to envision that the NPVRR "cost savings" customers will purportedly see from early RPS action will be more than offset by power costs that include PPAs with QFs that are $30/MWh higher than they should be.

52/ Docket No. UM 1396, Order No. 10-488 at 8 (Dec. 22, 2010).
53/ OAR 860-029-0040(4)(a).
54/ Order No. 10-488 at 8.
55/ Docket No. UM 1396, Order No. 11-505 at 6 (Dec. 13, 2011).
56/ Docket No. UM 1728, PGE Application, Sheet Nos. 201-15 & 201-16 (May 1, 2017).
57/ Id. Solar QF costs are similarly inflated during the deficiency period, with prices ranging between $28 and $35/MWh during the sufficiency period and rising to between $55 and $69/MWh in 2020.

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The irony of this is that the resource deficient avoided cost rates PGE will pay QFs in 2020 will not actually help the Company avoid the resource on which those rates are based. As the Commission has previously noted, in "a period of resource deficiency, the historical calculation of avoided costs has included both the variable and fixed costs of a planned resource *in order to reflect the actual deferral or avoidance of that resource*."[58/] That, at least, is how it is supposed to work. When a utility proposes to acquire a resource for purely economic reasons, however, the rationale for acquiring that resource is not impacted (or is impacted only slightly) by additional QF purchases. This is evident from the Company's own Reply Comments, where it updated its modeling to account for additional QF contracts entered into through December 2016.[59/] This, along with an updated load forecast, pushed its RPS need out further than in the IRP, but the economic rationale for early RPS action, according to the Company, is still compelling. The fully embedded cost of a new wind resource in 2020, in other words, is not a cost the Company avoids and, therefore, cannot represent its "avoided cost."

Yet, that is what customers will pay under the Company's proposal. The true impact of PGE's RPS Action Plan, then, will be to require customers both to pay for a resource they do not need, and to pay higher rates for QF power than they otherwise should have to. This is not a reasonable outcome.

B. The Company has not demonstrated its need for "dispatchable capacity."

There is little doubt that PGE is likely to have a capacity deficit in 2021 when Boardman retires. The size of this deficit, as well as the resources that should fill it, remains in

58/ Docket No. UM 1129, Order No. 05-584 at 26 (May 13, 2005) (emphasis added).
59/ PGE Reply Comments at 16 & Attach. B at 7.

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question, however. The Company has identified a need for "dispatchable capacity" in 2021 of between 375 and 550 MW.[60] This need has declined since PGE issued the IRP (due to a lower load forecast and an extension of the Company's contract for a share of the Wells Dam) by at least 135 MW.[61] Nevertheless, the Company has failed to meet the threshold requirement of justifying this need in the first place.

The Company's need for dispatchable capacity in particular is based at least in part on the system imbalances the Company projected from a 25% RPS penetration.[62] As both ICNU and Staff pointed out, however, the Company is doing this to itself.[63] It does not have a 25% RPS obligation until 2025, but is proposing to accelerate the variability issues the REFLEX model predicts by acquiring RPS resources before they are needed.[64] In fact, rather than accelerating these problems, the Company can delay them by waiting to acquire a new variable RPS resource until at least 2029 when it may actually need one. Perhaps by this time the best RPS resources will not be "variable" anyway.

Additionally, and somewhat remarkably, the Company admits that it did not evaluate the economic value of flexible resources and admits that the market could potentially provide a cheaper option than the type of "dispatchable capacity" sought in PGE's Action Plan.[65] As Staff points out, the REFLEX model used to develop the Company's "dispatchable capacity" needs was programmed to avoid purchasing from the market, even though day-ahead and hour-ahead market purchases are a common and low-cost means of addressing load and

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[60] PGE IRP at 343-44; PGE Reply Comments at 7.
[61] PGE Update to Reply Comments (April 13, 2017).
[62] PGE Reply Comments at 59.
[63] ICNU Opening Comments at 19-20; Staff Opening Comments at 21.
[64] PGE's RPS obligation in 2025 will be 27%. SB 1547 § 5(1)(e).
[65] PGE Reply Comments at 59.

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generation variability issues.[66/] The Company states that it "looks forward to further discussions about how to incorporate flexibility modeling into future IRPs."[67/] But the Commission is tasked with acknowledging the current Action Plan. The Company's Reply Comments show that such acknowledgement could lead to the acquisition of resources that are more expensive than suitable alternatives and are unnecessary to meet existing system requirements.

The Company's admission that it did not evaluate the economic value of flexible resources reinforces what ICNU, Staff, and the Citizens' Utility Board of Oregon ("CUB") have asserted – PGE should be relying more on the market by placing a greater emphasis on front office transactions, supplemented with what CUB calls "medium-term resources," i.e., 5-10 year products.[68/] These actions appear better able to provide the best combination of cost and risk for customers than a long-term resource. PGE's assessment that it can rely on the market only for up to 200 MW is, as Staff notes, out of synch with the fact that it relied on the market for over 33% of its retail load needs just four years ago,[69/] and as Mr. Mullins shows, is far below the transmission capacity it has at both Mid-C and COB.[70/] Other regional utilities rely heavily on the market for their capacity needs. Other than relying on the "real-time experience and professional judgement of its power traders," PGE has not explained why it is different.[71/] Further, as CUB notes, medium-term products in combination with a reliance on the market to

66/ Staff Opening Comments at 23.
67/ PGE Reply Comments at 59.
68/ CUB Opening Comments at 5.
69/ Staff Opening Comments at 23.
70/ B. Mullins Final Comments at 6-8.
71/ PGE Reply Comments at 55.

meet a portion of the Company's capacity needs provides "optionality and nimbleness," something the Company's proposed Action Plan notably lacks.[72]

The Company's need for "dispatchable capacity," therefore, has not been demonstrated. As Mr. Mullins' portfolio analysis demonstrates, the market provides the most cost-effective source of capacity.[73] Other regional utilities plainly understand this.[74] The Company should clearly and convincingly demonstrate that it needs "dispatchable capacity" in 2021 and why market transactions cannot effectively meet this need.

III. CONCLUSION

For the foregoing reasons, and as also discussed in ICNU's Opening Comments, the Company's RPS Action Plan fails to provide customers with either the least cost or the least risk compliance option, let alone the "best combination" of these two. Requiring customers to pay for a resource they will not need for over a decade is patently unreasonable and should not be acknowledged. The Company also has not adequately demonstrated its need for "dispatchable capacity" in 2021. The Company should be required to perform an analysis of its ability to rely on the market for capacity and demonstrate that deferring a new variable RPS resource will not eliminate its flexible capacity need.

72/ CUB Opening Comments at 4.
73/ B. Mullins Final Comments at 8.
74/ Id. At 7-8.

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Dated this 12th day of May, 2017.

Respectfully submitted,

DAVISON VAN CLEVE, P.C.

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Of Attorneys for the Industrial Customers of
Northwest Utilities

April 14, 2017

TO: Tyler Pepple
Bradley Van Cleve
Davison Van Cleve, P.C.

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC 66
PGE Response to ICNU DR No. 038
Dated April 7, 2017

Request:

Please provide Confidential Attachment A to PGE's Response to ICNU DR 012 in Docket No. UM 1788, updated with the most current information.

Response:

PGE objects to this request on the basis that it is overly broad. Subject to and notwithstanding its objection, PGE responds as follows.

Attachment 038-A summarizes PGE's QF contracts executed on or before December 31, 2016.

April 14, 2017

TO: Tyler Pepple
Bradley Van Cleve
Davison Van Cleve, P.C.

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC 66
PGE Response to ICNU DR No. 039
Dated April 7, 2017

Request:

Please provide Confidential Attachment A to PGE's Response to ICNU DR 016 in Docket No. UM 1788, updated with the most current information.

Response:

PGE objects to this request on the basis that it is overly broad. Subject to and notwithstanding its objection, PGE responds as follows.

Attachment 039-A summarizes PGE's unbundled REC inventory as of December 31, 2016. Attachment 039-A is protected information subject to Protective Order 16-408. Note that PGE has not yet retired RECs for the 2016 compliance year, so Attachment 039-A represents the unbundled REC inventory prior to REC retirements for 2016 RPS compliance.

Page 3 of Attachment A to ICNU's Final Comments contains Protected Information subject to Order No. 16-408 and has been redacted in its entirety.

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May 12, 2017

Oregon Public Utility Commission
Attn: Filing Center
201 High St SE, Suite 100
Salem, Oregon 97301

Re: LC 66 - Final Comments on behalf of ICNU on the 2016 Integrated Resource Plan of Portland General Electric Company

Dear Commissioners,

I appreciate the opportunity to provide Final Comments on behalf of the Industrial Customers of Northwest Utilities ("ICNU") on the 2016 Integrated Resource Plan ("IRP") of Portland General Electric Company ("PGE" or the "Company"). ICNU is a non-profit trade association representing large electric utility customers located throughout the Northwest, including customers of the Company. Tyler Pepple of Davison Van Cleve will also be providing Final Comments on behalf of ICNU in this matter.

In summary, I continue to recommend the Commission not acknowledge two supply-side actions in the Company's 2016 IRP Action Plan: 1) supply-side action "a. Renewable Resources," and 2) supply-side action "b. Capacity Resources."

In Attachment C Revised, I have updated my analysis of the Company's renewable portfolio standard ("RPS") compliance obligations through 2037. After updating for new loads and contracts with qualifying facilities ("QFs"), the need for a physical RPS resource does not occur until 2034. This gives me even greater confidence that a Just-in-Time ("JIT") strategy is a more prudent, and less risky, way to plan for RPS compliance. The Company's strategy, on the other hand, will result in increased costs of $336.5 million, on a net present value revenue requirement ("NPVRR") basis over the 20-year period 2018 to 2037.

With respect to Supply-side action "b.", the Company now asks the Commission to approve acquisition of 775 MW to 950 MW of capacity resources.[1/] Notwithstanding, fundamental questions remain unanswered regarding the Company's supply-side resource needs. A threshold planning issue for any utility in the Northwest is the degree to which market imports may be relied upon to provide resource adequacy. The Company, however, has made no attempt to analyze its ability to rely on market imports, and instead, suggests that it has relied solely on the judgement of its traders to derive its market assumptions. Relying on subjective judgements is not sufficient for the Commission to acknowledge the nearly $1.1 billion of capital additions the Company is planning with respect to this action item.[2/]

While I recommend the Commission not acknowledge supply-side action "b.", further study needs to be undertaken with respect to the Company's 2021 resource need. First, the Company needs to take a closer look at demand-side opportunities (including as large customer opt-out) prior to committing to the resource acquisitions it seeks in the 2016 IRP. Second, the Company needs to coordinate better with other regional utilities, such as Puget Sound Energy, which are also looking at potential resource additions in a similar timeframe. Third, we need a better understanding of the magnitude of the resource need, and the best type of resources to fulfill that need, including consideration of market import capability.

I. FINAL COMMENTS

In general, I continue to be concerned with the prospect of substantial capacity and renewable resource additions in the IRP action plan. The Reply Comments of the Company have given me little confidence that the action plan the Company proposes will result in a least-cost, least-risk resource portfolio to ratepayers. The portfolio the Company proposes may be preferred from a shareholder perspective, particularly given the $1.9 billion of capital that the Company would require to pursue its proposed plan.[3/] From a ratepayer perspective, however, the portfolio the Company proposes will result in real rate increases to consumers for resources which have not been adequately demonstrated to be necessary, nor optimal.

In my view, long-lived, physical resources should be constructed as a last resort. As we have seen with the early retirement of coal and nuclear plants, developing long-lived assets is inherently risky to ratepayers, and is becoming more so with increasingly rapid technological developments in the industry. While long-lived generating facilities may be economic in the

1/ PGE Reply Comments at 9, Table 1. Includes 375 MW to 550 MW of Dispatchable Capacity and 400 MW of Generic Peak Capacity. While the Company filed an update subsequent to its Reply Comments, to reflect the execution of a contract for output at the Wells hydroelectric facility, it is not clear how the update impacts the action plan proposal of the Company.

2/ Calculated based on the overnight capital requirements for a 550 MW Combined Cycle Combustion Turbine (approx. $0.6 billion) and a 400 MW LMS 100 Simple Cycle Combustion Turbine (approx. $0.5 billion) based on cost estimates in Appendix K of the 2016 IRP. This does not include capital requirements for the Company's proposed RPS resource.

3/ Includes $875.0 million in capital for 515 MW of wind additions, in addition to the $1.1 billion of capital necessary for the proposed supply-side additions.

early stages of their lives, technological change often leads to conditions that make generating assets less competitive in the later stages of their economic lives. When coupled with the environmental risks associated with constructing new thermal resources, the proposal of the Company to acquire upwards of 950 MW of unspecified capacity resources is a very risky proposition to ratepayers.

Given the magnitude and significance of the resources the Company proposes, the standard for the Commission to acknowledge the supply-side and renewable resources action items should be relatively high. Given unresolved issues, however, it cannot be reasonably said that the Company has satisfied the standard necessary to receive acknowledgment of its somewhat amorphous resource proposals.

Very basic questions remain unanswered in the Reply Comments of the Company. These issues must be resolved before we can even begin to consider potential resource decisions corresponding to the retirement of Boardman. These are issues that cannot be resolved as an afterthought in an RFP process. For example, the Company makes no attempt to quantify the amount of capacity available through Front Office Transactions ("FOTs"), a threshold issue for evaluating resource adequacy and an issue that was raised by nearly every party to this proceeding. In addition, there have been no attempts on the part of the Company to further study or specify the optimal type or timing of resource additions, as the 2016 IRP continues to be based on a fundamentally flawed methodology. Finally, updated information shows that an early action RPS compliance strategy is even more costly and risky to ratepayers than discussed in my Initial Comments.

II. RESOURCE ADEQUACY

In Initial Comments, I disagreed with the use of the RECAP model as the sole basis for evaluating the resource adequacy in the 2016 IRP. I also noted that the RECAP modeling was based on a number of faulty assumptions. Accordingly, I developed a traditional load and resource balance, using a Planning Reserve Margin ("PRM") methodology applied to the winter peak of the Company. This sort of PRM approach is consistent with the planning analysis that has been used in prior IRPs.

In Reply Comments, the Company suggests that a PRM analysis does not provide a meaningful assessment of its capacity requirements.[4/] In making these sorts of allegations, however, the Company does not really respond to the issues related to their RECAP modeling and assumptions raised in my Initial Comments. Instead, the Company just points to the very assumptions which I noted to be unsupported, or wrong, in the 2016 IRP.

For example, the Company criticizes my assumption of 300 MW of market capacity.[5/] Yet, it is the Company that has not provided any analysis to demonstrate what amount of market import

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4/ PGE Reply Comments at 51.

5/ Id. at 49-50.

capability is most appropriately assumed in its IRP. The Company also criticizes my analysis for applying an adjustment to reflect a more recent load forecast.[6/] Yet, the Company itself updated the load forecast in its updated resource adequacy assessment.[7/] Similarly, the Company criticized me because I did not perform an Effective Load Carrying Capability ("ELCC") study to calculate the capacity contribution of solar resources. Yet, my very concern was that the Company did not present an ELCC capacity contribution study for solar resources, and in fact, my assumptions were very close to the somewhat limited ELCC values the Company did present in its Reply Comments. Ultimately, it is the responsibility of the Company to demonstrate the reasonableness of the resource portfolio it proposes, and it should not fall to intervenors to prepare studies, such an ELCC study, that should have been included in the IRP when it was originally filed.

Thus, the Company's Reply Comments on resource adequacy largely miss the point. At a minimum, a PRM analysis is useful in understanding the magnitude and drivers of the Company's resource needs, and not, as the Company suggests, a meaningless analysis.

1. A Traditional Approach Based on a Planning Reserve Margin Should be Used to Evaluate Resource Adequacy Requirements

For many years, the Company has planned its system using a PRM of approximately 10% to 12%, a planning standard which clearly has produced reasonable reliability within the Company's balancing area. Notwithstanding, the Company has departed from the concept of a PRM in the 2016 IRP, and has instead relied solely on a new modeling tool, known as the RECAP model. I described the nature of the RECAP model in my Initial Comments, and the reasons why I believe the model is unsuitable to model reliability of utilities in the Northwest. For the most part, the Company did not respond to my concerns regarding the applicability of the RECAP model to utilities in the Northwest. The Company did not, for example, address the fact that, unlike the GENESIS model used by the Northwest Power and Conservation Council ("Council"), the RECAP model does not consider regional hydrology when establishing loss of load probability. Needless to say, the Council does not use the RECAP model when considering regional resource adequacy, nor does any utility in the region other than the Company.

In addition, the load and resource balance presented in my Initial Comments demonstrated that, based on the application of a 12% PRM to winter peak and after a number of corrections to the assumptions in the Company's analysis, the 2021 resource need was closer to 243 MW. I did not prepare a full update of this analysis for these Final Comments, although execution of new contracts with Douglas County PUD and QF developers indicate that the Company's 2021 resource need has declined. In fact, the Wells contract alone reduces the capacity need in 2021 to only 108 MW, based on the Company's filing.[8/]

6/ Id. at 49.

7/ Update to Figure 5 of PGE Reply Comments at 1, Figure 5 (Apr. 13, 2017).

8/ Id.

To be clear, it was never my intention to object to the use of loss of load probability modeling tools altogether. However, when those tools are used, it is important for them to be benchmarked against existing methodologies and values which are easy to understand and known to be reasonable.

In this case, the RECAP model would result in an effective increase to the PRM from 12.0% to approximately 19.4%.[9/] This material increase to the effective PRM is concerning because the Company has not provided any compelling explanation of why the RECAP model produces results that are so materially different from the levels that have been used in the past. This is particularly true considering the fact that a 12% PRM has produced reasonable reliability on the system of the Company for many years.

In Reply Comments, the Company suggests that a PRM is not a meaningful measure of resource adequacy.[10/] I disagree. Use of a PRM clearly has been a meaningful measure of resource adequacy in the past, as the concept has been used for decades in utility planning. In addition, similar deterministic PRMs are used by utilities throughout the West. The California Independent System Operator ("CAISO"), for example, continues to use a deterministic PRM for considering resource adequacy requirements of load serving entities within its balancing area. Thus, I find it somewhat disingenuous of the Company to claim that the consideration of its load and resource balance, under a PRM framework, does not provide any meaningful information whatsoever.

The Company's claim that a PRM approach applied to its summer peak produces results that are comparable to the RECAP model should also be given little weight.[11/] First, resource adequacy using a PRM methodology has historically been measured for the Company as a percentage of the Company's winter peak. As applied to the winter peak, the PRM approach has produced reasonable reliability in both the summer and winter seasons. Thus, it is appropriate to continue applying the PRM to the winter peak load and resource balance.

The Company's summer PRM assessment is also based on many of the faulty assumptions identified in my Initial Comments. For example, the Company assumed <u>zero</u> FOTs are available to meet summer peak loads, a clearly unreasonable assumption. The Company assumes an arbitrary 5% capacity contribution for wind and solar resources, even though its own ELCC studies produce capacity contribution values for wind of 11.5%.[12/] While the Company did not present a specific ELCC study for solar resources, the ELCC of all renewables was calculated to be 16.9%.[13/] Given these unrealistic assumptions, it is not

9/ <u>See</u> 2016 IRP, Volume II, Appendix P, Table P1. The 19.4% figure was calculated by taking the average of the values on the line TRM% over the period 2017 through 2021.

10/ PGE Reply Comments at § 4.2.3.

11/ <u>Id.</u> at 43.

12/ <u>Id.</u> at 46, Table 11.

13/ <u>Id.</u>, Table 10.

surprising that the PRM approach applied to summer peak produces results comparable to the RECAP model.

The Company also makes a slightly ambiguous assertion that the RECAP model produces similar end results as the PRM analysis performed in the 2013 IRP. [14/] That may be true, but is beside the point. The results of the 2013 IRP were based on different load and resource assumptions, which have been updated in this 2016 IRP: loads have declined; many contracts have been executed; new energy efficiency plans have been developed; etc. The results of the RECAP model for the 2016 IRP, therefore, are not appropriately compared to the results of the PRM analysis in the 2013 IRP. Rather, the RECAP analysis in the 2016 IRP can only be appropriately compared to the results of the PRM analysis based on the load and resource information in the 2016 IRP, as presented in my Initial Comments.

2. The Company Still Has Not Appropriately Considered Capacity Available from Front Office Transactions

For resource adequacy purposes, the 2016 IRP assumes that only 200 MW of market transactions are available for the winter peak and 0 MW of market transactions are available for the summer peak.[15/] In supporting these levels, the Reply Comments of the Company largely conflate the capacity available in the spot market with the capacity available from Front Office Transactions ("FOTs"). As the Company acknowledges, an FOT is a planning construct representing firm power purchases, including physical or financial power products.[16/]

As I understand its response, the Company basically acknowledges that it has access to capacity from FOTs in addition to the 200 MW and 0 MW of "spot market" transactions in the winter and summer, respectively. While the Company attempts to distinguish spot market transactions from FOTs, such a distinction is irrelevant. An electric utility will balance its system over time using a blend of FOTs and spot market purchases. Relying solely on spot market purchases for capacity, for example, may not be viewed as a very prudent way to meet load and resource requirements in a reliable manner. Notwithstanding, the Company suggests that FOTs have been considered elsewhere in its analysis, although not as a market import. Rather, the Company seems to suggest that the "generic capacity" resource additions that it includes in its portfolio modeling account for any FOT capacity available in the market.

I strongly disagree that the generic capacity resources in the Company's portfolio modeling are a reasonable proxy for FOT capacity available in Northwest power markets. The generic capacity resources in the portfolio model are simple cycle combustion turbines ("SCCT") (of the "frame" type) with a useful life of 30 years. A long-lived generating asset has different economic and risk attributes than market FOTs, and therefore, it is not appropriate to model

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14/ Id. at 43.
15/ Id. at 55.
16/ Id. at 56.

market purchases on the same basis as an SCCT. Once an SCCT is built, it is a permanent fixture of the Company's resource portfolio. The same is not true for market purchases.

Even if one were to conclude the generic capacity resources in the Company's preferred portfolio are a reasonable proxy for market purchases, the supply-side resource actions the Company proposes in the 2016 IRP would best be viewed as a need to acquire FOTs. An important distinction between FOTs and SCCTs, however, is that no RFP is required to procure FOTs. In fact, an RFP may restrict the ability for the Company to execute these types of transactions, which are typically entered into opportunistically on a continual basis, in a cost-effective manner.

Given the unique characteristics of the power markets in the Northwest, market reliance is usually a threshold question for resource planning. As noted in my Initial Comments, the Northwest power markets are unique because of 1) surplus capacity from the Bonneville Power Administration; 2) surplus capacity from the Mid-Columbia publics,[17/] 3) surplus capacity from British Columbia's Powerex; and 4) approximately 3,000 MW of in-region capability from independent power producers. As a result of these factors, it is common for Northwest utilities to rely more heavily on capacity available through bilateral markets for purposes of resource adequacy.

Yet, no analysis has been conducted on the part of the Company in order to quantify and better understand the amount of FOT market capacity that should be reflected in its load and resource balance. Instead of relying on an economic analysis of import capability, the Company bases its market capacity assumption solely on the experience and judgement of its traders.[18/]

While individuals may reach differing conclusions regarding the ability of the Company to transact in forward markets, simply relying on the alleged experience and judgement of traders is not sufficient for the Commission and parties to conclude that the Company is justified in pursuing upwards of 950 MW in capacity additions. In fact, given the unique characteristics of the Northwest, I am concerned with the judgement of those traders who might allege that there is zero market capacity available at the time of summer peak.

A comparison to PacifiCorp's latest IRP shows that the Company's judgment with respect to market capacity is not reasonable. In its 2017 IRP, PacifiCorp assumes 1,275 MW of available FOT capacity in the Northwest during both the summer and winter peaks. PacifiCorp assumes 775 MW of FOT capacity from the Mid-Columbia hub, 400 MW of FOT capacity from California-Oregon Border ("COB") hub and 100 MW of FOT capacity from the Nevada-Oregon Border ("NOB") hub.

17/ The Mid-Columbia Publics include: Grant PUD (Wanapum and Priest Rapids), Chelan PUD (Rock Island and Rocky Reach), and Douglas PUD (Wells).

18/ PGE Reply Comments at 55.

Similarly, Puget Sound Energy's 2015 IRP included an assumption that 1,397 MW of firm capacity is available from the Mid-Columbia market.[19/] Avista's 2015 IRP appears to allow for an unlimited amount of market purchases from the Mid-Columbia market.[20/] Even the CAISO allows California utilities to use import capability on Northwest interties, including from COB and NOB for purposes of meeting resource adequacy requirements. The CAISO assumes that approximately 3,008 MW and 1,283 MW of market import capability is available from COB and NOB respectively.

Given the transmission capability of PGE, there is no reason not to include a reasonable amount of market FOT capacity in the 2016 IRP. In response to ICNU Data Request 17, for example, the Company indicated that it has rights to approximately 727 MW of transmission from COB. Yet, unlike PacifiCorp, which assumed 400 MW of FOT capacity at COB, based on its long-term transmission rights, the Company assumed zero FOT capacity from the COB market in its analysis. Both PacifiCorp and PGE are owners of the California Oregon Intertie (COI), which is the transmission segment that runs from COB into the Northwest. PacifiCorp owns approximately 400 MW of transmission from COB and PGE owns approximately 950 MW of transmission from COB,[21/] although for PGE only 727 MW of northbound capability is available to the merchant operations. Thus, notwithstanding the fact that PGE has greater access to capacity from the COB market than PacifiCorp, PGE excludes FOT market capacity from COB altogether.

For purposes of my Initial Comments, I assumed that the Company had the ability to import approximately 300 MW of winter peaking capacity from the Mid-Columbia and COB markets, with the request that the Company provide further justification for its market assumptions in Reply Comments. While the Company criticized my use of 300 MW, the Company did not provide any concrete analysis to suggest that its capability to acquire FOTs is different than the values in my analysis, as I requested. Indeed, given the Company's transmission capacity from these markets, there is reason to believe its import capability is greater than 300 MW.

The Company's criticism of the 300 MW of FOT in my studies also missed the point of my analysis because my portfolio analysis actually assumed varying levels of market capability, including high, low, and medium market capability scenarios. The 300 MW FOT level was simply the medium scenario. The ultimate conclusion that I drew from studying those scenarios with varying levels of FOTs was that, without any doubt, market FOT purchases are the most cost-effective way for the Company meet its peak load requirements. Thus, market FOTs should be used to the maximum extent before acquiring any new physical resources.

19/ Puget Sound Energy, 2015 Integrated Resource Plan at G-3.

20/ Avista Corporation, 2015 Integrated Resource Plan, Chapter 10.

21 See COI Utilization Report at 13 (May 04, 2011), available at: http://www.oatioasis.com/WASN/WASNdocs/COI_Utilization_Report_S.Anners.pdf

This means that, prior to making any concrete plans to acquire new physical resources, it is critical to have a clear understanding of the precise amount of market capacity that can be relied upon to meet peak loads. Clearly, an assumption of zero is not reasonable.

3. The Company Should Explore Regional Solutions to Future Capacity Needs

In addition, I continue to support a regional approach to considering resource adequacy. I noted in Initial Comments that the Council recently published the Seventh Power Plan, and found that "[i]n more than 90 percent of future conditions, cost-effective efficiency met *all* electricity load growth through 2030 and in more than half of the futures *all* load growth for the next 20 years."[22/] The Company attempts to discredit the Council's regional reliability assessment by suggesting that the regional resource need is greater, resulting in a 10% to 13% LOLP, if one does not consider energy efficiency.[23/] This response is somewhat perplexing, however, since the Company is basically recommending that energy efficiency is not appropriately considered when evaluating regional resource adequacy.

Consistent with the results of the Council's Seventh Plan, I continue to believe that the Company should take no immediate action with respect to potential resource needs in 2021. Rather, I recommend that, prior to pursuing a physical resource, the Company should 1) continue to monitor its load forecast; 2) review availability of market imports; 3) continue to review demand-side options as alternatives to physical resource acquisition; and 4) coordinate with Puget Sound Energy regarding future resource needs in the region.

III. PORTFOLIO ANALYSIS

In Initial Comments, I also noted that that the portfolio analysis in the 2016 IRP was based upon a fundamentally flawed methodology. In contrast to other utilities, which use models to develop least-cost, least-risk portfolios, the analysis of the Company did not attempt to optimize the type and timing of resource additions. Rather, the Company performed a scenario analysis in the AURORAxmp model based on a series of predetermined resource portfolios, in an attempt to determine which preselected portfolio was the lowest cost. This type of analysis, which relied on generic capacity resources to fulfill resource needs, does not reflect an optimal resource portfolio, unless one believes that the Company preselected the optimal resource portfolio.

1. The Company's Portfolio Analysis Did Not Evaluate Resource Type or Timing

As noted in Initial Comments, one purpose of the IRP is to determine the lowest cost resources to acquire, as well as the proper timing of such resource acquisitions. This requires analysis of complex trade-offs between various types of resources, such as baseload, peaker, storage, and

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22/ Northwest Power and Conservation Council, Seventh Power Plan at 1-1 (Feb. 2016) (emphasis in original).

23/ PGE Reply Comments at 57.

market resources. The Company, however, uses sensitivity studies based on a limited number of pre-defined portfolios, which do not necessarily result in the optimal type or timing of resource acquisitions.

In the portfolio analysis presented in my Initial Comments, I concluded that the 2021 capacity need of the company is probably best resolved through the acquisition of an SCCT. I also concluded that other demand-side alternatives, such a large customer opt-out, may also be available to reduce the 2021 capacity need, reducing ratepayers costs.

The Company raises a few concerns with my portfolio analysis, although I am somewhat confused by the Company's responses because the concerns the Company raises with respect to my analysis are actually indicative of shortcomings in the Company's analysis.

For example, the Company suggests that my Portfolio 1 would produce loss of load expectation ("LOLE") of 18.2 hours/year,[24/] which as Staff has discussed is not necessarily an unreasonable level. Notwithstanding, the Company's assessment of the 18.2 hours/year loss of load expectation is based on the Company's faulty assumptions regarding market capacity and renewable capacity contribution in the RECAP model. As noted above, I established the resource adequacy of my portfolios based on the application of a 12% PRM. I disagreed with using the RECAP model for resource adequacy, particularly given the vast and unexplained difference between the resource adequacy levels demonstrated based on a PRM approach. The Company's reliability assessment of Portfolio 1, for example, does not consider the resource adequacy provided by market FOTs in the manner that I have considered those in my resource adequacy. Thus, the Company's concern with my modeling is simply a reflection of differing perspectives on underlying resource adequacy assumptions, which were discussed above.

Irrespective of what one may conclude with respect to the 12% resource adequacy assumption, the conclusions reached with respect to my portfolio sensitivity analyses still hold: 1) the Company's excessive resource adequacy standard will result in significant and unnecessary costs for ratepayers; 2) FOTs are the most cost-effective supply-side resources, to the extent available to serve peak loads; 3) the capacity needs of the Company decline if a large customer were to opt out of cost of service rates, providing significant benefits to remaining customers; 4) an SCCT is a more cost-effective way to satisfy the 2021 capacity need than a Combined Cycle Combustion Turbine ("CCCT"); and 5) pursuit of an early action strategy will result in increased costs to ratepayers.

2. An SCCT is More Cost-Effective Than a CCCT

With respect to my recommendation regarding an SCCT, the Company makes some statements that seem to argue that it was improper to include both FOTs and a SCCT, when comparing to the cost of building a CCCT. I believe the Company may misunderstand the reasons that an

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[24/] Id. at 88. (As an aside, the Company is not correct to characterize Portfolio 1 as my Preferred Portfolio, as it was simply used as a base case to perform sensitivity analysis.)

SCCT is likely a better resource to satisfy any 2021 resource needs, and the Company's response in this regard further demonstrates the flaws in the Company's planning methodology.

A flaw in the Company's planning approach is that it operates under the assumption that it is possible to build a fraction of a power plant. In actual operations, however, the decisions are much more binary, based on discrete plant alternatives. A utility must decide, for example, between building a 400 MW CCCT or 230 MW SCCT. Thus, if a utility is faced with a resource deficit of, say, 300 MW, it is not so straightforward to say that the 300 MW could be met with 300 MW of SCCT capacity. The utility surely could build the 400 MW CCCT to satisfy the 300 MW deficit. However, it may be more cost-effective for the utility to rely on a combination of an SCCT and FOTs, rather than building a larger, more expensive CCCT.

The Company's analysis, however, does not consider these types of resource alternatives. This is a fundamental flaw which was one of the very reasons for performing independent sensitivity studies in the first place. The Company's portfolio analysis requires any resource deficit (calculated in the RECAP model) to be met by a fraction of generic SCCT resource, irrespective of the fact that the Company cannot actually build a fraction of a power plant. As a result of this assumption, it is not possible from the modelling of the Company to consider the complex trade-offs that often occur when deciding between different resource alternatives with differing sizes. This shortcoming is important because these are the type of resource strategies that cannot be resolved after the fact in an RFP process and are necessarily resolved in the IRP before any RFP is issued.

In addition, contrary to the arguments that my analysis assumed FOTs at zero cost, costs for FOTs were included in my analysis based on forward market prices. FOTs were modeled in my analysis using the portfolio dispatch logic in the AURORAxmp model, which models the cost of market sales and purchases based on market prices, depending on whether the Company is in a long or short position. It is true that no additional capacity cost for FOTs was reflected in my analysis. Exclusion of capacity cost is appropriate, however, because FOTs are, by definition, acquired at market prices.

3. Large Customer Opt-out Should be Considered as a Resource Option

Finally, the Company also raises concerns with the notion that a large customer should be provided with the opportunity to opt out of cost of service rates, in order to reduce the Company's 2021 capacity need. If the Company truly believes that Northwest markets are really too risky and illiquid to rely upon to serve loads, then it ought to provide customers with the opportunity to assume that risk in order to avoid making significant, irreversible capacity acquisitions. Allowing a large customer to opt out could produce dramatic savings to remaining ratepayers, and for that reason, I continue to recommend that the Company consider it prior to making any physical resource decision.

As I noted in Initial Comments, the current transition adjustment methodology focuses solely on short-term marginal costs. It does not consider the long-term capacity benefit that the Company, and its remaining customers, receive when a large customer chooses to opt out of cost of service rates. There are also caps that have been put in place that restrict the amount of load that can migrate to direct access. Thus, prior to building a new resource, I recommend the Commission consider raising the current direct access cap and adopting transition adjustments that consider the long-term capacity benefits associated with incremental direct access customers, while still ensuring that remaining customers are unharmed.

IV. RENEWABLE PORTFOLIO STANDARDS COMPLIANCE

Based upon the portfolio analysis detailed in my Initial Comments, I demonstrated that early action will ultimately cost ratepayers $471.8 million on a net present value revenue requirement basis over a 20-year period. Since filing initial comments, the Company has executed a number of QF contracts that will allow it to meet a portion of its RPS requirements.

In Updated Attachment C, I detailed the impacts of the updated contracts and load forecast on the Company's forecast compliance obligations. As can be noted, the Company does not have a need for physical RPS compliance until 2034, assuming utilization of unbundled Renewable Energy Certificates ("RECs") up to the 20% statutory maximum level. Even if unbundled RECs are not considered, the Company would not have a RPS resource need until 2030. If the Company's proposal for early action is approved, the Company's REC bank will grow in an uncontrolled manner to 3,465 aMW by 2037.[25/] That is over 10 times the amount of RECs that the Company expects to generate in 2017, which in my view is an excessive level weighing against the Company's proposal for early action. Given this updated information, I strongly recommend against approving the Company's early action RPS strategy identified in the 2016 IRP.

1. The Company Should Adopt a Just-in-Time Acquisition Strategy for RPS Resources, Delaying RPS Resource Action Until 2034

I continue to recommend a "just-in-time" acquisition strategy for RPS resources, including utilization of unbundled RECs up to the 20% statutory maximum level. Based on the portfolio modeling presented in my Initial Comments updated for changes to the Company's RPS resource needs, the Company's early action proposal will cost ratepayers approximately $336.5 million on an NPVRR basis over the 20-year study period. Even if unbundled RECs are not considered, the early action portfolio still costs ratepayers $30.7 million on an NPVRR basis. Both of these NPVRR values exclude any provision for production tax credit ("PTC") carry-forwards, so if the uncertain tax position of the Company is taken into consideration, the actual cost to ratepayers of the Company's strategy may be significantly higher than these values. For these reasons, I continue to strongly recommend against acknowledgement of this aspect of the Company's action plan.

25/ Updated Attachment C at 2.

I have not yet fully reconciled my early action analysis with that the Company presents in Reply Testimony. I have, however, performed a high-level review of some of the workpapers underlying the Company supplemental early action analysis, and have a few observations.

First, it is important to note that, unlike my analysis of early action, the Company's analysis was not derived from the AURORAxmp portfolio analysis supplied in its initial filing. Rather, the Company's NPVRR analysis was performed outside of the AURORAxmp model, using a mark-to-market technique. That is, the Company simply compared the resource cost to the market value of energy it produces for differing resources and differing resource timing. There is not necessarily anything wrong with using a mark-to-market technique, although it is likely one of the reasons why my analysis produces different results relative to those of the Company. Note that my analysis uses the same resource adequacy standard in both the base case and the early action scenario. Thus, any concern of the Company regarding the reliability standard assumed in my analysis is irrelevant to the economics which were evaluated with respect to the various RPS scenarios.

In the Company's analysis, it isolates the mark-to-market value of only two possible resources at varying timing and quantities: 1) Pacific Northwest ("PNW") wind, and, 2) generic SCCT capacity. Since the PNW wind contributes to capacity, the Company reduces the size of the generic SCCT in its mark-to market calculations as the level of PNW wind increases. My portfolio analysis also considered the capacity contribution of wind, when evaluating the impacts of early action, albeit at a capacity contribution of 10%. The Company criticized my analysis for using wind capacity contribution values that were too high. Notwithstanding, the Company's early action analysis implies a capacity contribution for PNW wind of approximately 30%.

In addition, the Company's analysis accounts for the capacity contribution of wind in a different manner than my analysis because the Company assumes that wind resource additions will be capable of avoiding a fraction of a generic SCCT resource. As noted above, however, capacity resources must be acquired in discrete increments. Wind may delay the need to acquire a capacity resource, but it won't provide the opportunity to build, say, one-half of a SCCT.

The Company's analysis also produced some surprising results, which I believe warrant more investigation. For example, the Company's analysis would suggest that acquiring wind resource will actually reduce revenue requirement over the period 2017 through 2029. That is, the market value of generation is greater than the cost of the resources over that period. If that truly is the case then I might see some value in an early action strategy. The problem is, however, that the reduction in revenue requirement the Company is forecasting is entirely dependent on its projection of future prices and is inherently speculative. If prices are ultimately lower than the amounts assumed in its analysis, then the early wind resource will result in increased revenue requirement, meaning ratepayers would have been better off adopting a JIT strategy.

This concern is particularly pressing given that, in actual operations, the Company's wind resources have underperformed relative to the assumptions used when justifying those resources. The capacity factors assumed in the Company's Annual Update Tariff filings, for example, seem to decline every year. Based on my review of the Company's workpapers, the Company's analysis also assumes that wind will generate revenues at a rate of $55.45/MWh in 2029. In my judgement, structural changes that have occurred within energy markets, such as fracking, probably prevent power prices from increasing by such a degree relative to current levels. Be that as it may, it is a real risk to rate- payers if market prices do not escalate as forecast in the Company's analysis. If not, these proposed facilities will cost ratepayers greatly. What certainty can ratepayers have that the revenue requirement reductions forecast in the Company's model will come to fruition? Given the discretionary nature of the Company's strategy, I believe that the Company should bear all of the risk if the alleged revenue reductions forecast over the period 2017 through 2029 do not materialize.

The Company's delay scenario also includes RPS resource additions beginning in 2029, whereas my analysis forecast a need for RPS resources in 2034. This difference can be ascribed to the fact that the Company does not include unbundled RECs up to the statutory maximum, as included in my analysis. Although, I did perform an analysis that excluded unbundled RECs, showing a resource need in 2030. That portfolio produced only a modest NPVRR benefit relative to early action. Thus, most of the difference between my analysis and the Company's is related to the assumptions surrounding unbundled RECs.

Finally, the Company's analysis results in an excessively high REC bank at the end of the study period, which is another factor driving the differences between my economic analysis and that of the Company.

In addition, the Reply Comments of the Company do not address many of the other problematic aspects of the proposal for early action raised in Initial Comments. For example, the Company Reply Comments do not address any of the risks inherent in building a renewable resource prior to the time that such a resource is needed.

For example, there is a risk that future renewable resource prices will be less than what the Company forecasts in the 2017 IRP. If so, that will diminish the already unfavorable economics of its proposed strategy. As I noted in Initial Comments, the rapid pace of technological change with respect to energy resources creates a significant risk that acquiring new generation, renewable or otherwise, before it is needed will impose substantial stranded costs on customers. The Reply Comments of the Company do not consider this risk.

The Reply Comments also do not consider other rate impacts, including the fact that ratepayers will likely be faced with upward rate pressures as a result of replacing lost capacity associated with the retirement of Boardman. Thus, in addition to being based on questionable economics, the early action proposal will result in real rate increases to customers, who will not benefit from the resources for many years, if at all. This is a severe form of inter-generational inequity, where ratepayers are being asked to pay for costs not necessary for compliance for 17 years, and accordingly, should be viewed unfavorably.

As noted in my Initial Comments, there may be instances where it is appropriate to pay more in rates today in order to achieve long-term rate savings. These sorts of projects with a long-term pay-back are not preferred in periods when ratepayers are already subject to substantial upward rate pressures. In addition, the long-term rate savings must be far more certain, and imminent, to occur than suggested in the Company's RPS analysis. It may make more sense to pursue early action, if the Company's RPS resource need is only a few years into the future, and less sense if the resource need is in the distant future.

2. Use of Unbundled RECs Will Delay the Need for New RPS Additions until 2034

As noted, if the Company continues to rely on unbundled RECs, it will not need to acquire a new RPS resource until 2034. While the Company did model a sensitivity using unbundled RECs in its initial 2016 IRP, I noted in Initial Comments that the Company inappropriately assumed unbundled RECs could only be used for RPS compliance over the period 2016 through 2021.[26/]

In the NPVRR early action sensitives performed in its Reply Comments, however, the Company has assumed that no unbundled RECs would be used for compliance. Given the Company's history of relying on unbundled RECs for compliance, excluding consideration of unbundled RECs in its economic analysis is not a reasonable assumption. I continue to recommend that the Company assume utilization of unbundled RECS up to the 20% statutory maximum level for the entire study period.

3. Early RPS Build Scenarios Should Include the Cost of Incremental Production Tax Credit Carry-Forwards

As also noted in Initial Comments, the Company currently lacks sufficient taxable income necessary to utilize all of the PTCs generated from the Biglow Canyon and Tucannon River Wind facilities. The Company acknowledges this concern in its Reply Comments and prepares a number of analyses corresponding to the PTC carry forward analysis, that I prepared in Docket UM 1773. Based on its analysis, the Company suggests that the impact of PTC carry-forwards is largely immaterial. I disagree.

The Company's assessment is based on a number of speculative assumptions regarding its growth in its future taxable income, which may, or may not, ultimately come to fruition. Given the significant amount of plant that the Company seeks to add to rate base, however, I do not expect that the Company's taxable income to grow in the manner that it projects in its analysis. The resources the Company seeks to acquire through the 2016 IRP will result in a material amount of accelerated tax depreciation, which one expects to place downward pressure on the taxable income in future years. As far as I can tell from the hard-coded workpapers supporting its taxable income projection provided in Attachment F of the Company's Response to ICNU Data Request 31, the Company did not consider these factors when performing its analysis.

[26/] Mullins Initial Comments at 15.

This was evident to me because the Company did not prepare a separate tax provision calculation assuming the early action strategy was not adopted.

In fact, I am very concerned that the additional deductions resulting from its proposed capital additions could cause the Company to operate at a net operating loss in future tax years. I am also concerned with the prospect that tax reform could dramatically reduce the Company's ability to utilize PTC carry-forwards. At a minimum, these uncertain tax issues represent real risks to ratepayers, which are factors arguing against an early action strategy. I note that the Company was not willing to commit to limiting the rate impact to customers to the $33 million it calculated as the cost of PTC carry-forwards.[27/]

If the Company proceeds with its proposal for early action, however, ratepayers should not bear the risk associated with the potential inability of the Company to utilize PTC carry-forwards on its tax return, as those risks were not considered in the Company's analysis. If, for example, the future taxable income of the Company is lower than what the Company projects in this matter, the Company should bear the risk associated with any additional PTC carry-forward balances. It would be unfair to ratepayers for the Company to consider the carrying costs of any incremental PTC carry-forward balances in rates, since those amounts were not properly reflected in the economic analysis the Company has used to justify deviating from a JIT strategy.

Notwithstanding, even if one considers the Company's PTC carry-forward analysis to be correct, it is still not in customers' best interest to pursue an early action strategy, particularly considering that the Company's RPS resource need has been postponed until 2034. The $336.5 million of NPVRR cost that I calculated above excludes any provision for PTC carry-forwards.

V. CONCLUSION

I appreciate the opportunity to provide these comments on behalf of ICNU. I also appreciate the large amount of work and analysis conducted by the Company in preparing the IRP. Notwithstanding, I remain concerned that there are still fundamental questions that must be considered before making irreversible decisions to acquire the supply-side resources proposed by the Company.

With respect to the renewable resource addition, I continue disagree with the economic analysis proposed by the Company to justify the 515 MW of near-term renewable resources. The latest information demonstrates that it's now even less beneficial to ratepayers to pursue an early-action RPS strategy.

27/ PGE Resp. to ICNU DR 036.

In addition, the Company's proposal for upwards of 950 MW of supply-side capacity resources should also not be acknowledged. I continue to recommend that the 2021 need be further studied and analyzed by the Company prior to issuing an RFP.

I look forward to working with parties to further address the Company's future resource strategy.

Sincerely,

/s/ Bradley Mullins

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UPDATED ATTACHMENT C (Page 1 of 3)
SCHEDULE OF FORECAST RENEWABLE ENERGY CERTIFICATE ("REC") BALANCES, JIT RESOURCE ACQUISITION
Assuming unbundled RECs are used for compliance
Average-Megawatts

Year	Beg. Bank (a) = (d)[n-1]	RECs From Exist. Resrcs. (b)	Unbundled RECs (c)	New Resrcs. (d)	RPS Req. (e)	Ending Bank (f) = ∑ (a):(d) - (e)	
2016	896	321	59		295	982	
2017	982	338	59		293	1,086	
2018	1,086	338	59		295	1,188	
2019	1,188	338	59		295	1,290	
2020	1,290	422	79		396	1,396	
2021	1,396	422	80		399	1,499	
2022	1,499	422	80		402	1,599	
2023	1,599	422	81		407	1,696	
2024	1,696	422	82		412	1,789	
2025	1,789	422	113		563	1,761	
2026	1,761	422	114		569	1,728	
2027	1,728	422	115		576	1,690	
2028	1,690	421	117		583	1,645	
2029	1,645	414	118		590	1,587	
2030	1,587	414	155	-	774	1,382	
2031	1,382	363	157	-	783	1,118	
2032	1,118	334	159	-	793	818	
2033	818	330	160	-	802	506	
2034	*506*	*330*	*162*	*450*	*812*	*636*	*Resource Need*
2035	636	330	211	450	1,057	571	*Deficit Year*
2036	571	305	214	450	1,071	469	
2037	469	304	217	450	1,084	357	

UPDATED ATTACHMENT C (Page 2 of 3)
SCHEDULE OF FORECAST RENEWABLE ENERGY CERTIFICATE ("REC") BALANCES, EARLY ACTION
Assuming unbundled RECs are used for compliance
Average-Megawatts

Year	Beg. Bank (a) = (d)[n-1]	RECs From Exist. Resrcs. (b)	Unbundled RECs (c)	New Resrcs. (d)	RPS Req. (e)	Ending Bank (f) = ∑ (a):(d) - (e)
2016	896	321	59		295	982
2017	982	338	59		293	1,086
2018	1,086	338	59		295	1,188
2019	1,188	338	59		295	1,290
2020	1,290	422	79	175	396	1,571
2021	1,571	422	80	175	399	1,849
2022	1,849	422	80	175	402	2,124
2023	2,124	422	81	175	407	2,396
2024	2,396	422	82	175	412	2,664
2025	2,664	422	113	175	563	2,811
2026	2,811	422	114	175	569	2,953
2027	2,953	422	115	175	576	3,090
2028	3,090	421	117	175	583	3,220
2029	3,220	414	118	175	590	3,337
2030	3,337	414	155	175	774	3,307
2031	3,307	363	157	175	783	3,218
2032	3,218	334	159	175	793	3,093
2033	3,093	330	160	175	802	2,956
2034	2,956	330	162	175	812	2,811
2035	2,811	330	211	761	1,057	3,057
2036	3,057	305	214	761	1,071	3,266
2037	3,266	304	217	761	1,084	3,465

UPDATED ATTACHMENT C (Page 3 of 3)
SCHEDULE OF FORECAST RENEWABLE ENERGY CERTIFICATE ("REC") BALANCES, JIT RESOURCE ACQUISITION
Assuming unbundled RECs <u>are not</u> used for compliance
Average-Megawatts

Year	Beg. Bank (a) = (d)[n-1]	RECs From Exist. Resrcs. (b)	Unbundled RECs (c)	New Resrcs. (d)	RPS Req. (e)	Ending Bank (f) = ∑ (a):(d) - (e)	
2016	896	321	59		295	982	
2017	982	338	-		293	1,027	
2018	1,027	338	-		295	1,071	
2019	1,071	338	-		295	1,114	
2020	1,114	422	-		396	1,140	
2021	1,140	422	-		399	1,163	
2022	1,163	422	-		402	1,183	
2023	1,183	422	-		407	1,199	
2024	1,199	422	-		412	1,209	
2025	1,209	422	-		563	1,069	
2026	1,069	422	-	-	569	922	
2027	922	422	-	-	576	768	
2028	768	421	-	-	583	607	
2029	607	414	-	-	590	431	
2030	*431*	*414*	*-*	*500*	*774*	*571*	*Resource Need*
2031	571	363	-	500	783	651	*Deficit Year*
2032	651	334	-	500	793	691	
2033	691	330	-	500	802	719	
2034	719	330	-	500	812	737	
2035	737	330	-	650	1,057	660	
2036	660	305	-	650	1,071	545	
2037	545	304	-	650	1,084	415	