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January 24, 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 Opening Comments of the Industrial Customers of Northwest Utilities ("ICNU") in the above-referenced docket. Also enclosed is the redacted version of the Opening Comments of Bradley G. Mullins on behalf of ICNU.

The confidential portions of ICNU's comments are 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 pages of the **Opening 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 by hand-delivery.

Dated at Portland, Oregon, this 24th day of January, 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.	)))))))	OPENING COMMENTS OF THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

I. INTRODUCTION

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

Since 2014, PGE has added well over $1 billion to its rate base, primarily through the addition of three new generation resources – Port Westward 2, the Tucannon River Wind Farm, and the Carty Generating Station. These capital investments have put steady upward pressure on the Company's rates during a period of low prices in the competitive market, economically disadvantaging its customers and incentivizing those customers who have alternatives to pursue such options. Now, in its 2016 IRP, the Company seeks to double-down on this strategy, again proposing to acquire well over $1 billion (and potentially approaching $2 billion) in new generation resources. This will further exacerbate the disconnect between the cost of service from PGE and the cost of competitive alternatives. Worse, much of this generation the Company is pursuing for discretionary reasons based on its prognostications of

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what the energy industry will look like 30 years or longer into the future. PGE is not pursuing a least-cost, least-risk strategy to meet its resource needs.

Based on ICNU's review of the IRP, discussed in these Comments and the companion comments of Bradley G. Mullins, ICNU recommends that the Commission not acknowledge PGE's Action Plan items to issue requests for proposals ("RFPs") for new physical generation in 2018 to meet Oregon's renewable portfolio standard ("RPS") and for new capacity resources.

II. COMMENTS

The Commission's rules define an IRP as a "utility's written plan … detailing its determination of future long-term resource needs, its analysis of the expected costs and associated risks of the *alternatives* to meet those needs, and its action plan to select the *best portfolio of resources* to meet those needs."[1/] As ICNU interprets it, PGE's IRP fails to meet the requirements of this definition. The Company identifies its long-term future resource needs, but it does not evaluate "alternatives" to meet those needs, which means that the IRP is incapable of identifying the "best portfolio of resources" to meet those needs.

The Company identifies two discrete needs for which it states it must acquire resources – the need to meet Oregon's RPS and the need to fill an 819 MW capacity deficit in 2021.[2/] However, as noted in Mr. Mullins' comments, rather than testing the type and timing of various resource additions to meet those needs, PGE predetermined the type of resources to include in the 21 portfolios it analyzed and then simply tested each of these portfolios against

1/ OAR 860-027-0400(2) (emphasis added).
2/ PGE IRP at 343.

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each other under various hypothetical scenarios.[3/] This may demonstrate how these predetermined portfolios fare against each other under the Company's assumptions, but it does nothing to identify whether the resources it preselected are in fact least-cost and least-risk.

The consequence of the Company's failure to evaluate "alternatives" to meet its resource need is that all four of its top-performing portfolios score essentially identically, because they all contain essentially the same resources.[4/] PGE uses this as an excuse to propose open-ended RFPs that seek nearly any resource to meet the identified need. ICNU is not opposed in concept to RFPs that are broad in scope, but there are two problems with the Company's strategy.

First, the results of the RFPs already appear biased toward a predetermined outcome. Specifically, based on the results of the IRP, it is difficult to see how these RFPs could result in anything other than the acquisition of 175 aMW of wind that is eligible for 100 percent of the production tax credit ("PTC") and a mixture of gas-fired generation and seasonal capacity products. PGE, for instance, claims it will test the market for unbundled RECs, but its analysis in the IRP already dismisses an unbundled REC strategy in favor of a physical compliance strategy. Its IRP explicitly states that "PGE's Action Plan considers *only* those portfolios that include an RPS compliance strategy consistent with the acquisition of 175 MWa of RPS-qualifying resources eligible for 100 percent PTC …."[5/] Thus, it is unclear how an RFP for

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[3/] Comments of B. Mullins at 9.

[4/] These portfolios are: (1) Efficient Capacity 2021; (2) Wind 2018 Long; (3) RPS Wind 2018; and (4) Wind 2018). See PGE IRP at 337. All four of these portfolios assume the acquisition of 175 aMW of Gorge wind in 2018 and natural gas-fired generation in 2021. The only differences in these portfolios during the action plan horizon are whether additional wind is acquired in 2021 or not, the type of gas-fired generation that is acquired (combined cycle or simple cycle), and the amount of gas-fired generation acquired in 2021. Id. at 278.

[5/] Id. at 309 (emphasis added).

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RECs could be successful based on how the Company has constructed the IRP. Similarly, its capacity RFP seeks all manner of capacity products, but its IRP reserves 400 MW of this capacity for resources that are capable of addressing its projected flexibility challenges with greater variable generation on its system – resources to meet a need that can be deferred beyond 2025 and that were only considered to be gas-fired.[6/]

Second, if the IRP does not bias the results of the RFPs, and PGE truly is committed to issuing RFPs that "enable[] the market to propose broad-ranging resources …" then the IRP process appears to be a wasted exercise.[7/] If the "best portfolio of resources" to meet the Company's needs will be determined in the RFP process, rather than the IRP process, then there is no reason to do the analysis PGE has performed.

Below and in the comments of Mr. Mullins, ICNU discusses in detail the following findings and recommendations with respect to the IRP: (1) PGE's proposal to issue an RFP for physical RPS resources to be online in 2018 is not the least-cost, least risk strategy – relying on unbundled RECs to meet 20% of the Company's RPS compliance needs reduces costs for customers, defers the need to acquire additional physical generation, and maintains the Company's flexibility to adapt to future circumstances; and (2) the Company is likely to have a capacity deficit in 2021, but the size of this deficit is likely to be far smaller than the Company projects.

6/ Id. at 140; infra at 19-20.

7/ PGE IRP at 338.

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A. The Commission Should Not Acknowledge PGE's Action Plan Item to Acquire Near-Term RPS-Compliant Physical Resources.

PGE proposes in its Action Plan to "issue one or more [RFPs] for approximately 175 MWa of bundled RPS compliant renewable resources …" with a commercial operation date of 2018,[8/] even though its own analysis shows it can rely on its existing RPS resources and currently banked RECs until 2027.[9/] The stated purpose for this proposal is to maximize the value of the PTC before it phases out.[10/] PGE has not demonstrated this to be the least-cost, least-risk RPS compliance strategy.

First, the IRP is devoid of any justification for the quantity of RPS-qualifying resources it is seeking. Second, the Company's claim of economic benefits to customers from early action is greatly exaggerated.

Furthermore, even if one were to accept the assumptions in the IRP that establish an economic value to capturing the PTC, those economic benefits depend on the accuracy of its predictions of compliance costs up to 34 years into the future.[11/] There is simply no way PGE can do anything but speculate about such costs. Yet, its early action proposal locks customers into a compliance strategy that will force them to pay today's costs for meeting RPS requirements that will not exist for many years. This eliminates the potential for any flexibility to address changing technologies, legal requirements, or market developments that occur over the next ten years or more. In the face of such uncertainty, the prudent course of action is to defer significant capital investments to avoid the potential for stranded costs and ensure that the

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8/ PGE IRP at 343.
9/ See Figure 1, infra at 12.
10/ PGE IRP at 343.
11/ Id. at 55.

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Company's adaptability. In fact, as Commission Staff has previously noted,[12] this was Company's previous position. In its 2013 IRP update, it determined that delaying physical compliance with the RPS "provides a hedge against factors that pose future cost of compliance risks for PGE."[13] Thus, under no circumstances is it the least-risk strategy for PGE to issue an RFP for physical RPS-compliant resources in its Action Plan. It is also, for the reasons discussed below, very unlikely to be the least-cost strategy.

1. <u>The Company's proposal to acquire 175 aMWs of RPS resources is arbitrary and unsupported.</u>

PGE states that its IRP demonstrates that, "[w]hen considering an incremental physical RPS-qualifying resource, early action, which captures relatively more of the available PTC prior to phase-out, is preferable to deferring action."[14] The Company goes on to state that "[g]iven the portfolios assessed in this IRP, PGE's results demonstrate that procuring 175 MWa, with a resource commercial operation date (COD) in 2018 … results in a lower NPVRR than just-in-time compliance …."[15] As ICNU demonstrates below and in Mr. Mullins' comments, these conclusions are based on a number of flawed assumptions.

They also demonstrate the limitations of this IRP in determining the least-cost, least-risk portfolio. The vast majority of the portfolios the Company analyzed include 175 aMW of Gorge wind in 2018.[16] PGE then tests this resource addition in combination with various other resource additions through its 34-year planning horizon. What the IRP does not do anywhere, however, is explain how PGE arrived at 175 aMWs as opposed to any other amount.

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[12] Docket No. UM 1788, Order No. 17-004, Appen. A at 12 (Jan. 5, 2017).
[13] Docket No. LC 56, PGE 2013 IRP Update at 60 (Dec. 2, 2015).
[14] IRP at 308.
[15] <u>Id.</u>
[16] <u>Id.</u> at 278-81.

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When asked to clarify this, the Company simply stated that it "concluded 175 MWa of wind generation was a reasonable quantity that captured available tax credits without exceeding mid-term RPS obligations."[17/] In other words, the Company performed no analysis to determine how much RPS-compliant generation it should acquire in the near term to ensure the least-cost, least-risk portfolio for customers.

The only logical conclusion from the Company's statement is that it predetermined its IRP portfolios by inserting the amount of RPS-compliant generation it had previously sought to acquire in 2016 through an RFP that it ultimately canceled after the Commission refused to approve it.[18/] The decision to pursue 175 aMWs of RPS resources through the 2016 RFP was driven by a high-level analysis contained in the Affidavit of James Lindsay attached to the Company's application,[19/] which neither the Commission nor any party ever fully vetted.

The Commission refused to approve PGE's 2016 RFP largely because it was inconsistent with the Company's 2013 IRP (and, thus, could not comply with Guideline 7 of the Commission's Competitive Bidding Guidelines), and lacked the rigorous analysis needed to justify acquisition of a new generation resource that is traditionally included in an IRP.[20/] Indeed, at the June 7, 2016 Open Meeting, PGE's representative expressly acknowledged that

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17/ Attach. A at 10 (PGE Resp. to ICNU Data Request ("DR") 026).

18/ See Docket No. UM 1773.

19/ Docket No. UM 1773, PGE Petition for Partial Waiver of Competitive Bidding Guidelines and Approval of RFP Schedule, Exh. A (May 4, 2016). In fact, that analysis showed an even higher PVRR benefit from acquiring 253 aMWs of PTC-eligible resources, although PGE never explained why it did not propose to acquire this amount as opposed to 175 aMW.

20/ See Docket No. UM 1773, Order No. 16-280 (July 29, 2016). Guideline 7 of the Competitive Bidding Guidelines reads in part: "Commission review [of a draft RFP] should focus on: (1) the alignment of the utility's RFP with its acknowledged IRP …." Order No. 14-149, Appen. A at 2.

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"we haven't done the sort of full portfolio analysis that we would normally do in an IRP process."[21/]

The Staff Memo attached to the Commission's order taking no action on RFP approval provided Staff's interpretation of the requirement in the Commission's Competitive Bidding Guidelines that an approved RFP be consistent with the most recently acknowledged IRP. Staff concluded that this requirement was "tantamount to requiring that the Company demonstrate two things: *1) a need for resources; and 2) a least-cost, least-risk … strategy to address this need*."[22/] Staff noted that the need to comply with the new RPS mandated by SB 1547 was a real need, but that "there are multiple portfolio options which could achieve RPS compliance using different proportions of bundled and unbundled RECs, and combinations of PPA's and Company-owned resources with various magnitudes and acquisition dates."[23/] The analysis associated with the Company's RFP, however, was a "very limited analysis [and] is not a substitute for an IRP," Staff stated.[24/]

Yet, ironically, now that it has the opportunity in this IRP to undertake the rigorous analysis the Commission required, the Company has effectively deferred to the perfunctory analysis it performed to justify its RFP and that the Commission has already rejected as insufficient. Rather than using the IRP to identify the "best portfolio of resources" to meet its needs in the least-cost, least-risk manner, the Company uses the IRP to justify the resource acquisitions it has already determined to undertake.

21/ Comments of B. Simms at 56:54.
22/ Order 16-280, Appen. A at 7-8 (emphasis in original).
23/ Id. at 8.
24/ Id.

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2. The Company exaggerates the economic benefits of near-term RPS compliance.

a. The Company's planning horizon biases its results in favor of early-action.

To determine "a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers," the Commission's IRP guidelines require a minimum 20-year planning horizon and the use of a present value revenue requirement ("PVRR") cost metric.[25/] PGE's 2013 IRP used to a 20-year planning horizon.[26/] The 2016 IRP, however, calculates the PVRR of the portfolios analyzed over a 34-year planning horizon, without any explanation for the change.[27/] The effect of this is to overemphasize the projected savings associated with the Company's proposed near-term acquisition of an RPS resource. This is because early acquisition of physical RPS resources reduces the amount of RPS qualifying generation the Company needs to acquire in the outer years of its planning horizon. However, one cannot possibly forecast with any certainty what the costs (or even the technologies) of RPS resources built in 2040 will be. Thus, the Company's calculation of a PVRR benefit of early RPS action based on a 34-year planning horizon is based largely on speculative long-term costs of RPS compliance. As Mr. Mullins demonstrates, a near-term RPS acquisition will cost customers nearly $500 million on an NPVRR basis relative to a just-in-time strategy, when analyzed over a 20-year period.[28/]

25/ Docket No. UM 1050, Order No. 07-047 (Guideline 1.c) (Feb. 9, 2007).
26/ PGE 2013 IRP at 16.
27/ PGE IRP at 55.
28/ Comments of Br. Mullins at 13-14.

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b. The Company does not account for the fact that it cannot use PTCs.

The principal (if not sole) justification for PGE's proposal to acquire 175 aMWs of RPS-compliant resources by 2018 is to capture 100% of the PTC.[29/] That is why its portfolios only look at adding wind in 2018. As ICNU has pointed out in other dockets, this justification is seriously flawed.[30/] Not only does this strategy effectively dismiss the significant risks associated with acquiring physical resources well before they are needed (including the possibility that the PTC will be reextended before PGE actually needs a new RPS resource), it also ignores the fact that the Company's tax liability prevents it from using all of its PTCs in the year they are received. Mr. Mullins discusses the costs to customers associated with the Company's inability to use the PTC.

Despite previously acknowledging that ICNU is "correct" on this issue,[31/] the Company says nothing about it in the IRP. As Mr. Mullins' portfolio analysis demonstrates, however, these costs impact the economics of near-term action to acquire the PTC.[32/] It is inappropriate for the Company to pretend that a factor that influences the least-cost, least-risk RPS compliance strategy does not exist, particularly when the Commission itself, as well as its Staff, has expressed concern about this issue.[33/] The Company should analyze the impact the cost of PTC carry-forwards has on the economics of its RPS Action Plan.

29/ PGE IRP at 309.

30/ Docket No. UM 1773, ICNU Supplemental Comments (June 28, 2016); Docket No. UM 1788, ICNU Comments (Sept. 12, 2016).

31/ OPUC June 7, 2016 Open Meeting, Comments of J. Tinker at 59:50.

32/ Comments of B. Mullins at 15.

33/ OPUC June 7, 2016 Open Meeting, Comments of Comm'r Bloom at 59:22; Docket No. UM 1773, Order No. 16-280, Appen. A at 10.

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c. The Company's "minimum recommended REC bank level" is inflated and requires earlier acquisition of RPS resources than necessary.

Another driver of the Company's RPS acquisition strategy in the IRP is its "minimum recommended REC bank level." PGE currently uses its REC bank as a sort of insurance policy against bad outcomes. Specifically, the Company calculates the impact, in terms of aMW, of three distinct risk factors: (1) the in-service date of a future RPS resource is delayed between one and two years; (2) its existing RPS resources under-generate by 22 percent; and (3) the Company's load growth in a year exceeds its forecast by a certain amount.[34/] The Company then calculates the aMW impact of all three of these circumstances occurring simultaneously in a single year and over a two-year period.[35/] It then averages the one- and two-year outcomes to establish its "minimum recommended level."[36/]

There are a number of problems with the Company's approach. First, the Company's method of calculating its minimum REC bank leads to an excessive number of RECs in the bank. Because the RPS and the Company's load are assumed to increase over time, the amount of RECs needed to maintain the "minimum" level grows significantly until, as can be seen from Figure 1, below, by 2025 the Company must keep more RECs in its bank to maintain its "minimum" than its existing RPS resources generate today.

[34/] PGE IRP at 290-93.
[35/] Id. at 292.
[36/] Id.

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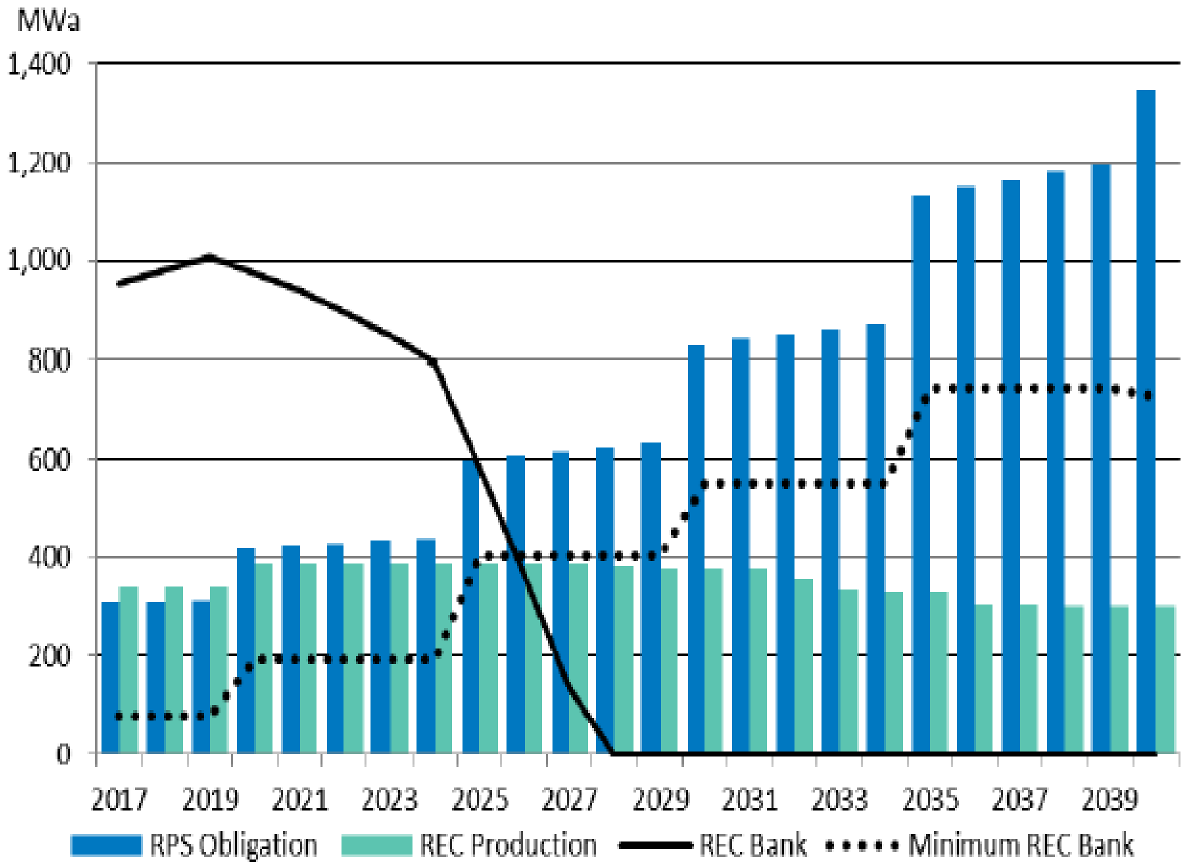
Figure 1[37/]



In other words, under the Company's methodology, resources customers are paying hundreds of millions of dollars for today in order to ensure the Company's compliance with Oregon's RPS will, by 2025, be used for nothing more than a safeguard against the "worst case" outcome.

Second, the need to maintain this excessive "minimum" REC bank leads to an earlier than necessary physical compliance need. As the graph above clearly demonstrates, the Company can comply with the RPS until 2027 with the resources it has today, even assuming it purchases no unbundled RECs in the future. Yet, the Company would need to acquire a new physical resource by 2025 in order to ensure it maintains its minimum REC bank.

37/ Reproduced from Figure 10-11 at page 293 of the IRP.

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Finally, the basis on which the Company developed its minimum REC bank is exceedingly unrealistic. The Company claims it needs to keep RECs in the bank in order to guard against the possibility that acquisition of a new RPS resource will be delayed, its existing RPS resources will significantly under-generate, and its load growth will greatly exceed its forecast, all at the same time for longer than one year. Such a circumstance has never happened to the Company. According to PGE's response to ICNU DR 008, in only one year – 2016 – did two of the risk factors occur at the same time.[38] Never have all three occurred simultaneously in the same year, and they have never come close to occurring simultaneously for two consecutive years. Moreover, the year in which two of the risk factors occurred at the same time is misleading because PGE cites its 2016 RFP as evidence of the risk of delayed acquisition. That RFP, however, was pursued for economic reasons (to capture the PTC), not because PGE needed a new physical resource to comply with the RPS.[39]

The RPS law has a mechanism for addressing the "worst case" scenario risk PGE is attempting to address with its minimum REC bank – Alternative Compliance Payments ("ACP"). ORS 469A.180 authorizes electric companies to make an ACP in lieu of retiring RECs for RPS compliance. This statute disfavors the use of ACPs as a compliance method, but surely there must be some scenario in which making an ACP is acceptable, otherwise the law would not allow for them. Indeed, parties who testified in favor of the RPS when it was first passed in 2007 cited ACPs as an appropriate means of complying with the RPS when it was the most cost-

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38/ Attach. A at 2-3.

39/ Docket No. UM 1773, PGE Petition for Partial Waiver of Competitive Bidding Guidelines at 5 (May 4, 2016).

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effective option. PGE itself testified that ACPs were "included to provide flexibility in meeting the targets, which can help keep costs down."[40/]

Ultimately, PGE should be able to demonstrate that customers are receiving value for the RECs they pay for. Consistently maintaining some amount of RECs in the bank to ensure flexibility and a cost-effective RPS compliance strategy may provide that value, but holding back RECs for a rainy day that is unlikely ever to come is nothing more than a waste of customer resources.

In the near-term, the appropriate "minimum" number of RECs to keep in the bank is immaterial. Figure 1, above, shows that PGE has far more RECs in its bank currently than it needs to comply with the RPS in the near-term. ICNU, therefore, recommends that PGE eliminate its minimum REC bank requirement and reevaluate it in future IRPs when the issue is more relevant.

d. The Company overstates the likely capacity factor of a Gorge wind resource.

The cost-effectiveness of physical RPS procurement in 2018 is likely further exaggerated by the fact that the Company assumes this resource will be Gorge wind with a 34 percent capacity factor.[41/] This capacity factor inflates both the energy production of the resource and the amount of PTCs generated.

40/ Attach. B at 1. See also, id. at 3, Testimony of J. Eisdorfer for the Citizens' Utility Board ("if the market for renewables spikes, the ACP … allows the utility to meet the [RPS] by making payments at a more reasonable rate …. This makes sure that customers get a good value for their money"); id. at 6, Testimony of S. Bolton for PacifiCorp ("The utility … can opt to use an alternative compliance payment when that option is most cost effective for customers").

41/ IRP at 197.

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The Company has consistently overestimated the capacity factor of its Gorge wind plants which, to date, have proven to be relatively poor energy resources. Phases I through III of Biglow Canyon were projected to have capacity factors of 37.3%, 36.3%, and 34.3%, respectively.[42] Tucannon was projected to have a capacity factor of 38.4%.[43] In no year have any of these resources achieved any of these capacity factors.[44] Indeed, in no year have these resources achieved the 34% capacity factor PGE assumes for Gorge wind in this IRP.[45] The Company itself has previously criticized ICNU for "overstat[ing] the expected PTC production for existing PGE wind facilities based on prior results which have *consistently* experienced a 10% reduction in comparison to forecasts."[46]

At a minimum, then, the Company should run a sensitivity analysis to determine the impact that a 10% reduction from the assumed capacity factor has on the economics of the Company's proposal for near-term RPS resource acquisition.

3. Delaying physical RPS compliance is the least-cost/least-risk strategy.

a. Relying on unbundled RECs reduces costs for customers and provides PGE with more flexibility to adjust to future events

This IRP is an extension of the dialogue ICNU has had with PGE over its post-SB 1547 RPS compliance strategy since the Company requested approval of its RFP in May 2016.[47] Since that time, ICNU has maintained that the Company should be pursuing a strategy of purchasing unbundled RECs in lieu of near-term physical compliance in order to reduce the costs

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[42] Attach. A at 4-5 (PGE Resp. to ICNU DR 024).
[43] Id.
[44] Id. at 7 (PGE Resp. to ICNU DR 024, Conf. Attach. C).
[45] Id.
[46] Docket No. UM 1773, PGE's Petition for Approval of Request for Proposals at 6 (July 13, 2016) (emphasis added).
[47] Docket No. UM 1773.

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of compliance and push out its need for physical resources.[48/] Mr. Mullins' portfolio analysis shows that his "Base Case" portfolio, which uses unbundled RECs in lieu of near-term physical compliance saves customers $471.8 million in PVRR over a 20-year period.[49/]

The Company has consistently responded that a strategy of relying on unbundled RECs is "strategically detrimental" because the unbundled REC market is illiquid and unpredictable.[50/] The Company asserts that this makes it risky to project reliance on unbundled RECs because one cannot predict the price these RECs will trade at in future years.[51/]

Given the circumstances the Company is currently in, its claim of untenable risks associated with forecasting reliance on unbundled RECs is a red herring. First, simply because the Company projects that it will purchase unbundled RECs in future years does not require it to do so. If the price of unbundled RECs in a year increases beyond the point that it is economic to purchase them, then the Company can rely on its existing resources and bank of RECs to meet its compliance obligation in that year. As can be seen from Figure 1, above, even if the Company purchases no unbundled RECs, it can meet its RPS obligations with its existing resources and REC bank through 2027. Foregoing the purchase of unbundled RECs in a particular year will not endanger the Company's ability to cost-effectively comply with the RPS. This flexibility is

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48/ Id., Supplemental Comments of ICNU at 5-6 (June 28, 2016); Response Comments of ICNU at 9-11 (July 19, 2016).

49/ Comments of B. Mullins at 10 (Table 2). A comparison of Portfolio 7 with Portfolio 1 shows the NPVRR cost of early RPS action. A comparison of Portfolio 0 with Portfolio 1 shows that the Company's preferred portfolio, which includes additional capacity acquisitions in addition to near-term RPS action would cost customers over $1 billion in NPVRR relative to Mr. Mullins' base case.

50/ Docket No. UM 1788, PGE Revised Renewable Portfolio Implementation Plan at 10 (July 15, 2016). It is, perhaps, not irrelevant to note that relying on unbundled RECs also provides fewer economic benefits to the Company's shareholders than physical compliance. While the Company appears more than willing to have customers assume the risks of acquiring physical RPS resources earlier than they are needed, thereby increasing returns for its shareholders, it is remarkably risk-averse when it comes to relying on unbundled RECs that provide no return for shareholders.

51/ PGE IRP at 287.

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in stark contrast to PGE's early action strategy, which will lock customers in to a compliance path that could become extraordinarily costly.

Second, the risk PGE cites with forecasting reliance on unbundled RECs appears minimal. While PGE may not be able to forecast the precise cost of unbundled RECs in the future (making them no different from any other future cost), this is largely irrelevant. What matters is whether the cost of unbundled RECs exceeds the price at which physical compliance is more cost-effective. The portfolio analysis Mr. Mullins performed using the AURORAxmp software shows that this "tipping point" cost for unbundled RECs would need to be $32.75.[52/] Regardless of the "illiquid" nature of the unbundled REC market, it is highly speculative for the Company to reject an unbundled REC strategy at this time when it has never purchased an unbundled REC for anywhere near this price and most recently purchased its full 20% complement of unbundled RECs for $0.33 apiece.[53/] If unbundled RECs do indeed reach $37.25, it may be appropriate at that time to reevaluate the timing of acquiring a physical resource. This is not the last IRP PGE will prepare. And again, simply because unbundled RECs reach a price of $37.25 or higher does not mean PGE must purchase them. It can rely on other strategies, including using banked RECs, purchasing bundled RECs from third parties, or making an ACP, if any of these alternatives proves to be more cost-effective.

Third, the Company's desire to avoid the "risks" associated with the unbundled REC market will almost certainly result in unnecessary costs for customers. The Company has

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52/ Comments of B. Mullins at 15. Under PGE's assumptions in the IRP, the benefits of capturing the PTC are so great that unbundled RECs would need to be priced negatively in order to make them cost-competitive with early action. PGE IRP at 310.

53/ Docket No. UM 1783, PGE 2015 RPS Compliance Report at 2. (June 1, 2016).

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historically used the full 20% of unbundled RECs authorized by the RPS.[54] If PGE continues to plan its future RPS compliance without assuming it will purchase any unbundled RECs, but in practice purchases enough unbundled RECs to meet 20% of its obligation, it will ultimately over-comply with the RPS by 20%, unnecessarily costing customers.

ICNU also notes that the Company's Action Plan includes a proposal to issue an RFP for RECs.[55] Such an RFP could mitigate the risks PGE envisions in predicting the unbundled REC market, as the Company could purchase up to its next five years' worth of unbundled RECs upfront, depending on the cost-effectiveness of the bids submitted.[56]

Ultimately, no party can guarantee the least-cost, least-risk long-term RPS compliance strategy. PGE, however, is adopting a "shoot the moon" strategy that is the least-cost only if many things it predicts out into the distant future actually happen. ICNU, conversely, is proposing a strategy that, in theory, could end up being higher cost, but is far more likely to be the lower cost option because it gives PGE flexibility to adapt its compliance strategy to account for unknown future circumstances. This also makes it the least-risk strategy.

b. The Company's analysis demonstrates that delaying acquisition of RPS resources may allow it to acquire a Montana wind resource and cost-effectively transmit it to its Balancing Area Authority ("BAA").

Not only is delayed compliance through a strategy of purchasing unbundled RECs to meet 20 percent of the Company's RPS obligation lower cost and less risky in and of itself as

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[54] 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. 1605, PGE RPS Compliance Report at 2 (June 1, 2012) (showing 183,063 unbundled RECs used for compliance).

[55] PGE IRP at 343.

[56] Section 7 of SB 1547 limits banking of unbundled RECs to five years.

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compared to an early physical compliance strategy, it also may lead to the acquisition of more effective RPS resources when physical compliance is indeed necessary. The Company's own analysis shows that a portfolio that substitutes a Gorge wind resource with a Montana wind resource yields $474 million in PVRR savings for customers.[57/] This is due to a higher capacity factor and the diversity benefits associated with a different wind shape. The caveat is that this savings does not incorporate the cost of transmission to bring the Montana wind resource into PGE's BAA.[58/] In the near-term, it may be difficult for PGE to acquire the transmission necessary to make Montana wind cost-competitive with other options, but delaying physical compliance could open up additional transmission options for the Company. Given the rapid development of markets in the West, it is difficult to predict what transmission facilities will exist a decade from now, and what the cost of that transmission will be. It is worth waiting to see whether the Company can cost-effectively capture the diversity and capacity factor benefits of Montana wind, as demonstrated by the Company's own IRP, rather than pursuing yet another low capacity factor Gorge wind resource.

c. Delaying acquisition of RPS resources may also delay the Company's need for flexible capacity.

A driving factor behind the Company's selection of its preferred portfolio is the need to acquire flexible capacity.[59/] The Company performed a flexible capacity study by using E3's REFLEX model in order to determine how best to meet the challenges of increased intermittent renewable generation in its BAA. The study found that, "at 25 percent RPS,

57/ PGE IRP at 312.
58/ Id.
59/ Id. at 146.

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approximately 400 MW of dispatchable resources will be required to avoid significant real-time imbalances on the system, but that this need could be met with a variety of technologies."[60/]

The Company's strategy of acquiring additional physical RPS resources in the near term, before they are needed, effectively imposes this challenge associated with a 25% RPS before a 25% RPS is required by law.[61/] In other words, not only does the Company's strategy of acquiring renewable resources in the near term require customers to pay for generation that is not needed to serve them or comply with state law, it also requires customers to pay for a more expensive source of capacity than may otherwise be needed during the Action Plan period. This is particularly egregious when one considers that, by eliminating its minimum recommended REC bank and purchasing unbundled RECs, PGE can delay the operational problems it forecasts with a 25% RPS beyond 2025.[62/]

B. The Company Overstates its Capacity Need

PGE's IRP projects a capacity deficit of 819 MWs by 2021.[63/] This is driven by an increased planning reserve margin relative to its 2013 IRP, projected load growth, potentially expiring contracts, and Boardman's retirement at the end of 2020. The size of this capacity deficit is the consequence of a series of assumptions that, collectively, likely result in a significant overstatement of PGE's capacity need. Mr. Mullins' analysis shows that a more realistic projection of the Company's capacity deficit in 2021 is 243 MWs, less than one-third of the Company's projection.[64/] Because, as Mr. Mullins also shows, PGE will be capacity

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60/ Id. at 140. The "variety" of technologies the Company analyzed are all gas-fired.
61/ This requirement will not exist until 2025, when Oregon's RPS rises to 27%.
62/ Comments of B. Mullins, Attach. C.
63/ PGE IRP at 114.
64/ Comments of B. Mullins at 5 (Table 1).

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sufficient until 2021,[65] ICNU recommends that PGE delay issuing an RFP for capacity resources at least until the second half of 2018, when the Company's capacity need will be clearer. This timing is similar to how long it took PGE to select and build Port Westward 2, its newest flexible capacity resource.[66]

1. <u>The Company's increased planning reserve margin is a "solution in search of a problem."</u>

In its 2013 IRP, the Company utilized a 12 percent planning reserve margin.[67] In the 2016 IRP, the Company states that it "determined that it needed a loss-of-load assessment to re-benchmark the capacity need, given the changes to the resource stack."[68] It also finds that "its process would be improved by developing a single comprehensive and internally consistent loss-of-load model for assessing capacity need, determining renewable capacity contribution, and evaluating portfolio reliability.[69] The Company uses E3's RECAP model to achieve this goal and inputs a loss of load expectation ("LOLE") of 2.4 hours per year into the model.[70] The result is a planning reserve margin of approximately 19.4%.[71] Mr. Mullins discusses the RECAP model and the Company's changes in more detail.[72]

From a policy perspective, PGE's proposal to increase its planning reserve margin recalls similar changes Puget Sound Energy ("Puget") proposed in its 2015 IRP. Specifically, among other things, Puget proposed to change from the 5 percent loss of load probability

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65/ <u>Id.</u>

66/ The Commission approved PGE's final draft RFP that resulted in Port Westward 2's selection on June 7, 2012. Docket No. UM 1535, Order No. 12-215 (June 7, 2012). Port Westward 2 was placed into service on December 30, 2014. Docket No. UE 283, Attestation of Maria M. Pope (Dec. 31, 2014).

67/ PGE 2013 IRP at 48.

68 IRP at 115.

69/ <u>Id.</u>

70/ <u>Id.</u> at 116.

71/ <u>Id.</u> at 850; Comments of B. Mullins at 2-3.

72/ Comments of B. Mullins at 2-4.

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("LOLP") metric, favored by the Northwest Power and Conservation Council, to an Expected Unserved Energy ("EUE") metric, and determined the appropriate EUE by calculating the economic value of reliability to customers.[73] The result was the equivalent of a 20 percent planning reserve margin.[74] The Washington Utilities and Transportation Commission ("WUTC") declined to acknowledge these proposed changes. Referring to Puget's calculation of the economic value of reliability to customers, the WUTC stated that, "[w]hile this analysis is interesting from the perspective of economic theory, it appears to be a solution in search of a problem. [Puget] does not identify any deficiencies in the current 5 percent LOLP standard or identify the last curtailment event driven by insufficient generation on [Puget's] system, stating only that it was more than 20 years ago."[75] The WUTC went on to find that Puget "carries a substantial burden to justify a change in the historical planning standard, especially when the change results in significant ratepayer impacts. As [Puget] has not met this burden, we reject the planning standard proposed by PSE."[76]

Although different from Puget's, PGE's proposed changes to its planning reserve margin suffer from the same infirmity. Despite proposing to increase its planning reserve margin from 12 percent to an average of 19.4 percent, the Company admits that:

> In the past 20 years, PGE has not experienced an outage as a consequence of generation resource inadequacy (NERC Energy Emergency Alert Level 3, or EEA3). Resource planning by PGE and neighboring entities to meet reliability obligations and emergency protocols required by WECC and NERC Reliability

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[73] WUTC Docket Nos. UG-141169/UE-141170, Puget 2015 IRP at 6-5 – 6-7.
[74] Id. at 6-16.
[75] WUTC Docket Nos. UG-141169/UE-141170, Attachment to the WUTC Letter to K. Johnson at 4 (May 9, 2016).
[76] Id.

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> Standards and coordinated with Peak Reliability have been successful at providing a stable regional grid.[77]

Therefore, while ICNU supports the Company's continuous efforts to improve its processes and the way it plans its system, if PGE is to do this in a way that materially increases customer costs, it should "carry a substantial burden" to explain why such changes are necessary. Here, the Company fails to identify any inadequacy with its existing 12% planning reserve margin and, therefore, has not met this threshold requirement to justify changing it.

2. <u>The Company's load forecast may be exaggerated and relies on stale data.</u>

Another driver of the Company's projected capacity deficit is its assumed long-term load growth, which PGE projects at 1.2% annually.[78] This is lower than PGE has forecasted in most of its recent IRPs,[79] but is still far higher than its annual load growth over the past ten years, which averaged a meager 0.4%.[80]

Additionally, the Company's projected growth is driven by outdated information. Mr. Mullins notes that the Company does not use its own most recent peak load projections.[81] It also relies in part for its reference case load forecast on the Oregon Office of Economic Analysis' ("OEA") May 2015 Economic Forecast and Global Insight's May 2015 U.S. Economic Forecast, analyses that are well over a year old.[82] Since that time, the OEA has published updated Economic Forecasts, which have been less bullish on the Oregon economy. Its most recent forecast, issued in December 2016, finds that "[j]ob growth in recent months has

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[77] Attach. A at 1 (PGE Resp. to ICNU DR 007).

[78] PGE IRP at 100.

[79] Docket No. LC 43, PGE 2007 IRP at 4 (June 29, 2007) (forecasting 2.2% long-term load growth); Docket No. LC 48, PGE 2009 IRP at 31 (Nov. 5, 2009) (forecasting 2.2% long-term load growth); Docket No. LC 56, PGE 2013 IRP at 2 (Mar. 27, 2014) (forecasting 1.3% load growth).

[80] Attach. A at 9 (PGE Resp. to ICNU DR 025, Attach. A).

[81] Comments of B. Mullins at 6-7.

[82] PGE IRP at 100 n. 55.

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decelerated somewhat from the full-throttle rates seen in the past couple of years" and concludes that "the state today is now past its peak in terms of growth rates."[83/] While Oregon still outpaces the national average in terms of economic growth, it appears that the OEA's economic outlook for the state is more pessimistic than it was when it drafted the report PGE relies on in the IRP. ICNU continues to evaluate the Company's projected load growth, but recommends at a minimum that PGE update its load forecast to include the most current data.

3. The Company has not demonstrated that it cannot renew existing contracts.

PGE's projected capacity deficit is further influenced by its assumption that it will not renew any of its existing contracts once they expire.[84/] The most significant of these is PGE's right to approximately 20% of the Wells Dam, which provides the Company with 133 MW of capacity.[85/] This contract is set to expire on August 31, 2018.[86/] PGE states that it is seeking to renew this contract.[87/] Because any capacity deficit the Company must fill with physical resources will not occur until 2021, PGE should wait to develop and issue a capacity RFP at least until after it knows whether the Wells contract will be extended.

III. CONCLUSION

ICNU recognizes the significant amount of time and effort the Company put into the IRP, and appreciates the challenges that PGE's IRP team confronts in addressing the numerous and diverse stakeholder interests. This team has consistently conducted itself with

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83/ OEA December 2016 Economic Forecast, available at: https://www.oregon.gov/das/OEA/Documents/forecast1216.pdf.
84/ See PGE IRP at 115 (Figure 5-1).
85/ Id. at 379.
86/ Id.
87/ Id.

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professionalism and has worked with ICNU throughout the IRP process. Nevertheless, ICNU cannot support the Company's Action Plan as constructed. As discussed above, numerous assumptions that underlie this Action Plan are fundamentally flawed. The analysis performed in the companion comments of Bradley Mullins demonstrates that there are lower cost, lower risk alternatives to the Company's Action Plan items that seek the addition of new physical RPS and capacity resources. ICNU recommends that the Commission not acknowledge these Action Plan items as the Company proposes. While it may be appropriate for the Company to acquire additional capacity in 2021, the least-cost, least-risk Action Plan does not include any physical resources at this time.

Dated this 24th day of January, 2017.

Respectfully submitted,

DAVISON VAN CLEVE, P.C.

/s/ Tyler C. Pepple
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Of Attorneys for the Industrial Customers of
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December 2, 2016

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. 007
Dated November 18, 2016

Request:

When was the last time PGE experienced an outage as a consequence of resource inadequacy? Please explain the circumstances of this outage.

Response:

In the past 20 years, PGE has not experienced an outage as a consequence of a generation resource inadequacy (NERC Energy Emergency Alert Level 3, or EEA3). Resource planning by PGE and neighboring entities to meet reliability obligations and emergency protocols required by WECC and NERC Reliability Standards and coordinated with Peak Reliability have been successful at providing a stable regional grid.

December 2, 2016

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. 008
Dated November 18, 2016

Request:

Reference Table 10-7: REC Bank Risk Factor Scenario, on page 292 of the IRP.

2.1.1 Has PGE ever experienced a scenario in which all three risk factors listed in the table occurred simultaneously in a single year? If so, please identify the circumstance.

2.1.2 Has PGE ever experienced a scenario in which all three risk factors listed in the table occurred simultaneously in two consecutive years? If so, please identify the circumstance.

Response:

2.1.1: Table 10-7 quantifies the amount of RECs appropriate to bank to hedge against several REC supply risk factors.

The 'Annual RPS Deferral Risk' factor protects against the potential for a delayed or unsuccessful procurement effort for RPS eligible resources. PGE has conducted unsuccessful competitive solicitations for RPS resources. Specifically, the 2008 RFP and the 2016 RFP led to little or no renewable resource additions despite PGE's effort to acquire RPS eligible generation.

The 'Annual Forecast Generation Risk' factor protects against the potential for RPS eligible generation to generate less RECs than forecasted. Specifically, this risk factor is designed to protect against a twelve-month consecutive period when actual generation is 22% less than was forecasted in the contemporaneous period. PGE has experienced twelve-month consecutive periods when generation from the Biglow and Tucannon facilities was at least 22% less than forecast, ending in years 2012, 2015, and 2016.

The 'Annual Load Forecast Risk' factor protects against the potential for retail load to exceed forecast on an annual basis. Specifically, this risk factor is designed to protect against retail load conditions when actual loads are approximately 1.9% higher than was forecasted. PGE has experienced loads that exceed its year ahead budget forecast by more than 1.9% due to factors including changes in large customer loads and weather in two of the last ten years – 2011 and 2014.

2.1.2 Please see the response for 2.1.1.

December 13, 2016

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. 024
Dated November 29, 2016

Request:

For each of the Biglow Canyon and Tucannon River wind facilities, please identify:

2.1.1 The assumed capacity factor at the time PGE determined to construct the facility;

2.1.2 Any third party PGE engaged to estimate the capacity factor for each facility and provide the associated reports and documentation; and

2.1.3 The actual capacity factor for each full year that the facility was in operation. Please update your answer when 2016 results are available.

Response:

2.1.1

The assumed capacity factor of Biglow Canyon Phase I at the time PGE determined to construct the facility was 37.3%. At the time of the decision, PGE had not yet identified the preferred wind turbine manufacturer. The assumed capacity factor reflected the Garrad Hassan's 2005 wind assessment which anticipated development of three Biglow Canyon phases with General Electric 1.5 MW SLE turbines.

The assumed capacity factor of Biglow Canyon Phase II at the time PGE determined to construct the facility was 36.3%. At the time of the decision, PGE had identified Siemens as the preferred wind turbine manufacturer. The Siemens SWT 2.3-93 turbines selected for the project have a greater rotor diameter and produce more energy than the GE turbine assumed in the Garrad Hassan 2005 wind assessment. Those benefits led PGE to increase the Garrad Hassan's forecasted capacity factor by approximately four percent.

The assumed capacity factor of Biglow Canyon Phase III at the time of PGE's decision to construct the facility was 34.3%. For the reasons detailed above, the assumed capacity factor is approximately four percent higher than was forecasted in the Garrad Hassan wind assessment.

The assumed capacity factor of Tucannon River Wind Farm at the time PGE decided to construct the facility was 38.4%.

2.1.2

Attachment 024-A includes Garrad Hassan's 2005 wind assessment of Biglow Canyon wind farm.

Attachment 024-B includes GL Garrad Hassan's 2013 wind assessment of Tucannon River wind farm.

2.1.3

Attachment 024-C includes the actual capacity factors for Biglow Canyon and Tucannon River wind farms.

Attachments 024-A, 024-B, and 024-C are protected information subject to Protective Order No. 16-408.

[redacted]

[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]

[redacted]

December 13, 2016

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. 025
Dated November 29, 2016

Request:

Please provide the total average annual load growth on the Company's system for each of the past 10 years.

Response:

Please reference Attach 025-A for PGE's weather adjusted annual energy deliveries growth rates for 2006-2015.

LC 66 PGE Response to ICNU DR No. 025
Attachment 025-A
Page 1

PGE's ANNUAL WEATHER ADJUSTED SYSTEM ENERGY DELIVERIES GROWTH

YEAR	GROWTH RATE
2006	2.7%
2007	0.9%
2008	0.8%
2009	-2.7%
2010	-1.4%
2011	1.3%
2012	0.6%
2013	0.1%
2014	0.8%
2015	1.2%

December 13, 2016

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. 026
Dated November 29, 2016

Request:

ICNU understands that the majority of the portfolios PGE analyzed in the IRP add 175 aMWs of wind generation in 2018. Please explain how PGE arrived at 175 aMWs, as opposed to some lesser or greater number.

Response:

PGE's analysis demonstrates that exceeding near-term RPS targets to capture expiring tax credits lowers Renewable Portfolio Standard (RPS) compliance costs. This pattern can be observed in Figure L-1. PGE concluded 175 MWa of wind generation was a reasonable quantity that captured available tax credits without exceeding mid-term RPS obligations.

MEASURE: SB 838
EXHIBIT: E
Energy and the Environment
DATE: 4-16-07 PAGES: 1
SUBMITTED BY: Dave Robertson

Portland General Electric
Dave Robertson, Director of Government Affairs
House Committee on Energy and the Environment
Hearing on SB 838, Renewable Energy Standard
4/16/07

- Good afternoon, Chair Dingfelder and members of the committee, my name is Dave Robertson, and I am the government affairs director for Portland General Electric. Thank you for allowing me to testify today on SB 838, the Renewable Energy Standard bill.

- PGE supports SB 838 and urges the committee to pass it.

- PGE has been actively involved in the discussions developing the compromise language that you see before you today. We participated in the Governor's Renewable Energy Working Group during the interim, and also in a smaller discussion groups with many of the parties you will hear from on this issue.

- Since last year, PGE has said that it could support a thoughtful, meaningful RPS that balanced the needs of our customers while ensuring that that reliability and safety of the electric supply system was not diminished.

- To achieve those goals, PGE executives developed a list of priorities that would have to be met in order for PGE to support an RPS. The priorities included:
    - Ensuring that the Oregon Public Utility Commission has the necessary authority to implement the RPS
    - Minimizing rate effects through the use of a cost cap
    - Tying the RPS to the OPUC's integrated resource planning process
    - Ensuring cost recovery for prudently incurred costs; and
    - Applying the RPS to all load-serving entities

- We believe SB 838 meets these priorities and provides us with the flexibility needed to meet the renewables targets set out in the bill:
    - The bill recognizes some of the contribution that hydropower makes toward a carbon free environment by allowing 50 megawatts, per utility, of low-impact hydro to count as a renewable resource
    - The utilities' RPS implementation plants are tied to the existing OPUC Integrated Resource Planning process. This will ensure that the best combination of "least-cost, least risk" energy resources are obtained to meet growing customer demands
    - The cost cap contains language that ensures a true apples-to-apples comparison of resources
    - An Alternative Compliance Payment plan is included to provide flexibility in meeting the targets, which can help keep costs down
    - Renewable Energy Credit banking is allowed and those credits can be acquired from the entire US Western electric grid, which also helps manage costs
    - The amendments apply the RPS to all load serving entities eventually
    - Timely recovery of utility costs is allowed if those costs are prudently incurred
    - Allows utilities to do more energy efficiency projects for residential and commercial customers if they are deemed a "least-cost, least-risk" resource for customers.

- Thank you again for the opportunity to comment on this bill.

MEASURE: SB 838
EXHIBIT: P
Sen. Environment & Natural Resources
DATE: 03/15/07 PAGES: 2
SUBMITTED BY: Jason Eisdorfer

Before the Senate Environment and Natural Resources Committee

SB 373

Jason Eisdorfer, Citizens' Utility Board

March 15, 2007

Cost Cap.
This provision is not a rate cap. If the Public Utility Commission authorized a 7% rate increase for costs associated with health care costs, a new customer information system, or a new fossil-fuel base load plant not associated with renewable energy, then this cost cap is not implicated at all. This cost cap says that if the cumulative difference between the levelized costs of renewable energy resources and comparable market-priced non-renewable energy resources reaches 4% of the utility's revenue requirement, then the utility need not meet the annual renewable targets. At such time as the cumulative difference falls below the 4% level, then the utility must meet the targets again.

This 4% is neither a guarantee of a 4% cost increase, nor is it meaningless. Renewable resources over time may be at market or, especially after the advent of carbon regulation, could cost less than the comparable fossil-fuel resource. If renewable resources are consistently higher than other comparable resources, we think that it is highly unlikely that the cost cap will be triggered in early years of the RES. However, if renewable resources are consistently more expensive, over the long term, as the costs of renewable energy acquisitions add up, the 4% cost cap ensures that customers will not pay too much to implement the standard

The costs that fall under this cost cap will undergo two prudence reviews: first, the rate-based resource will undergo the standard PUC prudence review, and second, through the compliance report, the PUC will determine the prudence of the utility's choice of resources (be they owned or contracted resources, or purchases of unbundled renewable energy certificates, or payment of alternative compliance payments) to meet the renewable standard.

Cost Recovery
There is a new provision that directs the PUC to identify a mechanism whereby the utility can apply for and get timely recovery of prudently incurred investment in renewable resources without the need for a rate case. This makes policy sense, because the RES will promote a strategy of adding renewable resources on an on-going basis, and this might otherwise require annual rate cases, which are resource intensive proceedings. In addition, as a renewable resource comes on line, the utility's variable costs, or costs of fuel, go down and those savings will be passed on to the customer through annual rate adjustment that are currently in place. It is not warranted to allow cost reductions to flow

through to customers from this RES and not allow for reasonably contemporaneous recovery of the fixed costs of the resource. Furthermore, the opportunity to recover fixed costs between rate cases currently exists at the PUC; this provision is to formalize the process in a more consistent way between utilities.

This cost recovery provision is NOT:
a) recovery of costs that are not used and useful in violation of Measure 9 (ORS 757.355). That existing statutory provision says that a utility may not recover the cost of an investment until the investment is actually turned on and is benefiting customers. The term "construction" in the proposed SB 373 bill language refers only to utility-built, or utility-constructed, resources as opposed to purchased resources. The term does not mean to imply that the utility can recover the costs of construction before the plant goes on line and is actually serving customers. All the parties agree to this interpretation;

b) preapproval of a resource. The cost recovery is of prudently incurred costs only, so whatever mechanism the PUC adopts as a result of this statute, the PUC must assume a prudence review of an operating resource in the process.

<u>Alternative Compliance Payment</u>
In addition to the cost cap there is an alternative compliance payment provision. While the cost cap protects customers from spending too much to meet the requirements of the RES, the ACP protects customers from getting too little value under the cost cap. So if the market for renewables spikes, the ACP, set annually by the PUC, allows the utility to meet the RES standard by making payments at a more reasonable rate to put into a fund for future renewable resource or energy efficiency investment. This makes sure that customers get a good value for their money.

MEASURE: SB 838
EXHIBIT: Z
Sen. Environment & Natural Resources
DATE: 03/15/07 PAGES: 5
SUBMITTED BY: Scott Bolton

3/15/07

Testimony of PacifiCorp on Senate Bill 373

Chair Avakian, Members of the committee, for the record my name is Scott Bolton, Government Affairs manager for Pacific Power. Along with me today are Kyle Davis, PacifiCorp Manager of Environmental Policy & Strategy, and Brent Gale, Senior V.P. – Legislation & Regulation of MidAmerican Energy Holdings Company, to help answer questions. We are pleased to come before the committee and offer our impressions of the amendments to the Senate version of the Oregon Renewable Energy Act that are currently being negotiated.

PacifiCorp is an integrated electric utility serving approximately 1.7 million customers in six western states. In Oregon, the company serves more than 550,000 retail customers as Pacific Power. We are one of the lowest-cost electric providers in the state and indeed the region.

PacifiCorp fully supports the goal of including cost-effective renewable energy as part of a balanced portfolio. PacifiCorp's generation capacity is currently more than 10,400 megawatts from coal, hydro, gas-fired combustion turbines and renewable wind and geothermal power. The system peak demand is about 9,400 MW, with the Oregon peak demand about 2,700 MW. Oregon retail sales are about 15 million MWh annually.

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PacifiCorp has about 1500 MW of hydro-electric generation, about 37 MW of geothermal generation, approximately 300 MW of wind generation and 53 MW of other renewable generation or purchase contracts such as biogas and biomass. The fastest growing portion of our resource mix is renewable energy. Since the completion of the sale from Scottish Power to MidAmerican Energy Holdings Company one year ago this month, PacifiCorp has embarked on an aggressive renewable energy plan that has added almost 400 MW of renewables and is expected to add another 1000 MW to 1500 MW of additional cost-effective renewable energy into our portfolio by 2014.

This expansion of our renewable portfolio has occurred without a renewable portfolio requirement. For PacifiCorp, renewable energy makes both environmental and business sense. Portfolio diversification is a critical tool to help manage the risks associated with coal and natural gas, including the costs of future carbon regulation at the state, regional, federal and even international levels.

When evaluating a renewable portfolio standard for Oregon, we are primarily concerned that the costs to our customers are reasonable and all parties, including utilities, are treated fairly. Oregon utilities will be the fiduciary agents of this policy - and PacifiCorp does not shy away from advocating for good public policy when it serves to benefit our customers or exposing bad policy when it does not. For us, addressing these concerns is paramount. And we greatly appreciate the time and effort the stakeholders involved in this issue have spent with us to address our concerns.

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While we are still reviewing the language, the amendments to the legislation that are being negotiated with the supporters of the bill appear workable, provide cost protections for our customers, treat parties equitably and provide utilities an opportunity to negotiate for the lowest-cost renewable energy to satisfy the standard. Allow me to highlight these improvements:

- Assurance of reasonable costs– The amendments allow utilities more flexibility to comply with the standard and allow compliance alternatives when the costs of compliance would be too high. The utility may generate the renewable energy necessary to comply with its target, or it can acquire renewable energy certificates (with a much wider geographic market than previous versions of the bill that provides for greater opportunities for competition and reduced costs), or it can opt to use an alternative compliance payment when that option is most cost effective for customers. These are important consumer protections in the event costs of compliance become too high in a particular year. The amendments also contain a 4-percent-of-revenue-requirement cap, established by the public utility commission.

- Planning – We have listened to our customers, in particular our larger industrial and commercial customers, who wanted a transparent and complimentary resource planning process. We asked for, and the amendments contain, a clear tie-in between

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the existing Integrated Resource Planning process and the implementation planning required by the amendments. This tie-in allows our regulators to look at investor-owned utility resource planning in a holistic fashion and allows our customers and the general public significant opportunity to weigh in and comment. We see this as a substantial improvement in the bill and should address the reasonable concerns we share with our customers to ensure that the renewable portfolio standard process is compatible with, and integrated into, the integrated resource planning process.

- Investment in new resources – The amendments incorporate other improvements to protect customers while not discouraging utility investment in renewable energy facilities. The amendments allow for the recovery of utility investment costs at the time the benefits of renewable energy are delivered to customers. This provision will still permit strong regulatory oversight and allow customers and their advocates the opportunity to review these investments without forcing long, expensive general rate cases. Importantly, this provision will also allow customers to receive the benefits of production tax credits much faster than the current process.

As I noted, PacifiCorp supports the goal of using renewable resources to the extent they are cost effective and do not adversely impact the reliability of the system. PacifiCorp believes that compliance with a standard perhaps as much as 15 percent should

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be achievable in a cost-effective way without compromising our system integrity or operational reliability.

We do want to note for the record some concern about the standard as we move into the later years and the targets increase to 20 and 25 percent. Today's technologies and operations indicate that these targets could potentially present operational challenges. However, we urge the Legislature to treat this standard as a living policy, to be revisited and fine tuned as experience, technologies and market conditions determine.

We share the hope and optimism of many of those who have testified to this committee -- as well as Governor Kulongoski -- that innovation and competition for renewable energy development and technologies will help us to achieve cost effective implementation of this renewable standard. The amendments to the bill that are being negotiated will help the state achieve that objective.

We are happy to take your questions.

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January 24, 2017

Oregon Public Utility Commission
201 High St SE, Suite 100
Salem, Oregon 97301

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

Dear Commissioners,

I appreciate the opportunity to provide initial 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. In addition to these comments, Tyler Pepple of Davison Van Cleve will also be filing comments on behalf of ICNU in this matter.

In summary, I 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."

With respect to Supply-side action "a.", my analysis demonstrates that a Just-in-Time ("JIT") strategy is a more prudent, and less risky, way to plan for renewable portfolio standards ("RPS") compliance. Such a strategy would postpone the need for a physical RPS compliance until 2030, or beyond.

With respect to Supply-side action "b.", the Company has not demonstrated a near-term need to acquire a supply-side capacity resource. My analysis shows the Company is surplus in capacity until the winter of 2021. After accounting for potential market purchases, the 2021 deficit is only approximately 243MW. Rather than issuing an immediate request for proposal ("RFP") for this potential capacity need, I recommend the Company pursue a flexible approach. Specifically, I recommend that the future capacity need be further monitored and studied by the

Company over the next two years, considering changes in loads, availability of market purchases, and other demand-side alternatives. This will provide the Company with greater flexibility in planning for this need, if conditions—such as loads, contract extensions, resource availability, demand response opportunities—change.

I. COMMENTS

In general, ICNU is concerned with the prospect of substantial capacity and renewable resource additions in the IRP action plan. The Company has just completed a series of major capital projects, including the construction of three large utility-owned generating facilities: Port Westward II, Tucannon River Wind, and Carty Generating Station. These three generating facilities collectively consisted of over $1.2 billion in capital and have placed material upward pressure on the Company's rates in recent years. This recent rate pressure, however, would seem small relative to the potential rate increases associated with the proposal in the action plan for 850 MW of thermal capacity and 515 MW of Pacific Northwest wind capacity.

Put simply, the analysis in the 2016 IRP is inadequate to justify such significant resource actions. The significant amount of work and effort undertaken by the Company to prepare the IRP is appreciated. The Company's analysis, however, fails to answer some basic questions—such as the amount of capacity available through front office transactions—and is based on certain methodologies with which ICNU fundamentally disagrees.

My concern with the Company's approach can be categorized into three general areas. First, I disagree with the proposed resource adequacy assessment, based on the black-box, Renewable Energy Capacity Planning Model ("RECAP") model. Second, I disagree with several aspects of the methodology employed to conduct portfolio analysis. Third, I disagree with the methodologies used by the Company to evaluate various RPS compliance strategies. Each of these areas will be discussed in the sections that follow.

II. RESOURCE ADEQUACY

In the 2016 IRP, the Company proposes a new methodology for evaluating resource adequacy, based on the RECAP model. RECAP is an unlicensed, freely available computer program developed by the California-based consulting firm Energy + Environmental Economics ("E3"). Given its black-box nature, ICNU does not necessarily believe it is appropriate to use the RECAP model in Oregon to establish resource adequacy requirements for the Company. Rather, the use of a traditional, Planning Reserve Margin ("PRM") is a more straightforward, proven way for the Company to evaluate resource adequacy. As it has been deployed, the RECAP model would result in an effective increase to the PRM from 12.0% to approximately 19.4%. [1/] Yet, the existing PRM has produced reasonable reliability in the

[1/] See 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.

Company's service territory for many years. Accordingly, the Company's proposal to increase the PRM is inappropriate. Given the peaking capability of the Northwest hydroelectric system and other unique characteristics of the region, the Northwest Power and Conservation Council calculated a winter Adequacy Reserve Margin—a functional equivalent of a regional PRM—of 0.1% in 2026,[2/] a value which is directionally and conceptually inconsistent with the Company's proposal to increase its effective PRMs by 61.6%.

1. The RECAP Model is Not Suited to Model Resource Adequacy in the Northwest

The RECAP is a compilation of python computer programs and excel spreadsheets, which rely on a "[n]eural network model […] to estimate complex relationships between inputs and outputs using hidden nodes that weigh and transform input data and optimize fit to output data."[3/] The model was developed for use in California and is highly complicated. Due to its black-box nature, the results it produces are also not necessarily transparent or easy to understand. In fact, when benchmarked against the PRM used in the 2013 IRP, it produces materially different results that cannot be reconciled in a straightforward manner.

While the RECAP model was developed in California, it is not actually used by regulators in California for resource adequacy. Resource adequacy requirements for California utilities have historically been based on a deterministic PRM, similar to that which PGE has historically used.[4/] There have been efforts in California to move towards a more probabilistic approach. My understanding, however, is that the modeling tools used to develop those studies are much more comprehensive than the RECAP model, relying more on historical data and less on data extrapolated through use of neural network models.

The RECAP model is not suitable to evaluate resource adequacy for utilities in the Northwest. Unlike many other regions, hydroelectric conditions are the principal driver of reliability in the Northwest. Accordingly, regional hydrology should be a principal consideration in evaluating resource adequacy for any utility located in the Northwest. Yet, the RECAP model only considers a limited time series of historical hydro data and does so only for Company resources.

Markets in the Northwest also are different than in California. With a substantial amount of surplus market capacity available through the Bonneville Power Administration, the Mid-Columbia publics,[5/] British Columbia's Powerex, and approximately 3,000 MW of in-region capability from independent power producers, it is common for utilities in the Northwest to rely more heavily on capacity available through bilateral markets for purposes of resource

2/ Northwest Power and Conservation Council, Seventh Power Plan, at 11-23, Table 11-7 (represents the average of Q4 and Q1) (Feb. 2016).

3/ E3, Renewable Energy Capacity Planning Model, User Manual at 7 (June 17, 2015)

4/ See e.g. CAISO, April 21st Public Workshop, Regional Resource Adequacy Revised Straw Proposal at 26-34. Available at http://www.caiso.com/Documents/Agenda-Presentation_RegionalResourceAdequacy-RevisedStrawProposal.pdf

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

adequacy. A critical question in evaluating the Company's resources adequacy is the extent to which the Company should rely on regional markets. The RECAP model, however, does not attempt to determine the depth of markets in the Northwest.

In fact, it is a flaw of the 2016 IRP that it did not analyze the degree to which the Company can rely on market purchases to satisfy load requirements in a reliable manner. Given the depth of the markets in the Northwest, as well as availability of a substantial amount of winter import capability from California, market availability should be a fundamental question addressed by the IRP of any utility in the Northwest prior to building a new resource.

Notwithstanding, the Company assumed little-to-no market capability in the RECAP model, and the market capability that was included was modeled in a way that is inconsistent with how the RECAP model is designed. The RECAP model contains special inputs to model market imports. The Company, however, did not use those designated inputs for market imports in its RECAP analysis. The Company set the market import capability in RECAP to zero, and instead modeled market purchases as if they were a variable energy resource, based on a historical profile of market purchases. Based on the way that the RECAP model generates stochastics, treating historical market purchases the same way as an intermittent resource does not accurately reflect the actual capability the Company derives from the market, and accordingly, is a flawed methodology.

In contrast to the methodology used by the Company, my opinion is that it is more appropriate to consider regional resource adequacy when evaluating the amount of available market capacity. The Northwest Power and Conservation Council (the "Council") recently published the Seventh Power Plan. In that document the Council 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."[6/] While the Council's recommendation was based on an ambitious forecast for demand response additions, the Council's report suggests that there will be sufficient regional capacity, an indication that surplus capacity in the region will likely be available through bilateral markets.

Due to these deficiencies, I recommend that the Commission not accept the RECAP model for evaluating the resource adequacy requirements of the Company. On its face, the RECAP model produces results that are unreasonable relative to the Company's past planning practices and fails to adequately consider unique aspects of the power supply system in the Northwest.

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

Rather, I recommend that the Commission evaluate the resource adequacy requirements of the Company using a traditional approach, relying upon a deterministic PRM. This sort of

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

approach is a simpler way to gain an understanding of the Company's resource needs and to evaluate resource alternatives to satisfy those needs.

Appendix P of the 2016 IRP contains a high-level load and resource balance. However, I have identified several problems with the load and resource balance presented in Appendix P, many of which will be discussed below.

As a result of these problems, I developed an independent load and resource balance, in an attempt to better understand the resource needs of the Company in the coming years. My analysis is more detailed than that presented by the Company in Appendix P and provides a more realistic assessment of the Company's capacity position following the retirement of Boardman. My analysis has been provided in Confidential Attachment A and is summarized in Table 1, below.

TABLE 1
Preliminary Load and Resource Balance (MW, Winter Peak)
No Resource Additions

	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	2040
Resources											
Coal	809	809	809	296	296	296	296	296	296	-	-
Natural Gas	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851
Hydroelectric	804	804	804	804	804	804	804	584	574	574	574
Renewable Resources	84	84	84	84	84	84	84	84	81	81	72
Qualifying Facilities	82	82	82	82	82	82	82	82	82	81	81
Seasonal Contracts	100	100	-	-	-	-	-	-	-	-	-
Total Existing Rsrcs	**3,730**	**3,730**	**3,630**	**3,117**	**3,117**	**3,117**	**3,117**	**2,897**	**2,885**	**2,587**	**2,578**
Net Load + PRM	**3,633**	**3,645**	**3,611**	**3,660**	**3,671**	**3,686**	**3,705**	**3,729**	**3,904**	**4,108**	**4,343**
Net Position (Before FOT)	**97**	**85**	**18**	**(543)**	**(554)**	**(569)**	**(588)**	**(831)**	**(1,019)**	**(1,520)**	**(1,765)**
Available Front Office Transactions*	300	300	300	300	300	300	300	300	300	300	300
Net Position (After FOT)	**397**	**385**	**318**	**(243)**	**(254)**	**(269)**	**(288)**	**(531)**	**(719)**	**(1,220)**	**(1,465)**

* Preliminary assumption to be updated in Final Comments

As can be seen from Table 1, the Company is faced with little, to no, near-term peak load growth, after accounting for incremental demand-side management and distributed generation resources. The above analysis also shows that, after the retirement of Boardman beginning in 2021, the Company is faced with a capacity need of approximately 243 MW. This need is substantially less than the 850 MW capacity resource addition proposed by the Company. Some of the differences between my load and resource analysis and the Company's are detailed as follows.

Planning Reserve Margin

As noted, the Company's analysis assumed an approximate 19.4% PRM. While I believe that a 12% PRM used in the 2013 IRP is too high—particularly given the fact that the

Council has determined that regional adequacy margins are closer to zero—for purposes of this proceeding, I used a 12% PRM to evaluate the Company's expected resource needs in Confidential Attachment A. That PRM is reflected in the Net Load values detailed above. Demand side resources are also reflected as an offset to Net Load in the above table, in contrast to the tables detailed in Appendix P, which separately detail demand-side resources in a manner similar to supply-side resources.

Front Office Transactions

In Appendix P, the Company assumed that only 98 MW of market transactions would be available in 2021 to meet peak loads. This assumption is largely unsupported in the 2016 IRP, and based on my experience, is arbitrarily low.

For purposes of the initial analysis summarized in Table 1, I assumed that the Company had the ability to import approximately 300 MW of winter peaking capacity from the Mid-Columbia and California-Oregon Border ("COB") markets. This is a preliminary assumption and may still be unrealistically low, given the Company's transmission access to regional markets. Accordingly, the Company should provide further information regarding available market capacity in its Reply Comments.

In its Reply Comments, I particularly request that the Company consider that it has a substantial amount of import capability from the COB market. In response to ICNU Data Request 17, for example, the Company indicated that it has rights to approximately 727 MW of transmission from COB. Customers are paying for transmission from COB, and thus, should be reaping the reliability benefits associated with access to that market. Because California is summer peaking, the Company should able to realize a significant amount of capacity from this transmission link. Just as PacifiCorp includes import capability from COB in its IRP, the Company should also consider COB imports in its IRP.

Load Forecast

Both the load and resource balance and RECAP analysis prepared by the Company appear to have been based on an outdated load forecast. In the Company's final MONET update in Docket No. UE 308, for example, 2017 peak loads were approximately 97.5 MW lower than reflected in Appendix P to the 2016 IRP. Similarly, loads in the RECAP model were overstated by an even greater amount, approximately 187.7 MW, compared to the load forecast provided in MONET in Docket No. UE 308. The difference between the peak load forecast in RECAP and the peak load forecast in the Company's load and resource balance may offer one explanation for the excessively high planning reserve margin assumed in the Company's analysis.

Based on the final MONET update, my analysis makes a 97.5 MW downward adjustment to peak loads in Attachment A.

These variances in the Company's load forecast are particularly concerning given a recent report by the Berkeley National Laboratory that demonstrated that many utilities, including the Company, have systematically overstated load growth rates in historical IRPs. A copy of that report, titled "Load Forecasting in Electric Utility Integrated Resource Planning" can be accessed as of January 2017 through the following hyperlink: https://emp.lbl.gov/sites/all/files/lbnl-1006395_0.pdf.

Load forecasts are one of the more important aspects to consider when evaluating resource adequacy, and thus, should be updated based on the best information available to the Company. It certainly would not be prudent for the Company to follow through with its plan to acquire a major resource, based on an outdated load forecast. This is one of the reasons I believe it is appropriate for the Company to continue to monitor its load forecast and resource needs for a few more years, prior to taking any concrete resource actions for 2021.

<u>Hydro Capability</u>

In forming its peak load and resource balance, the Company has understated the capacity available from its hydro electric facilities. It appears that the Company has used average annual energy to assess the capacity contribution of run-of-river hydro systems. Because the Company is winter peaking, it would be more accurate for the Company to assume average energy during the winter timeframe. My load and resource balance calculates capacity contribution based on average energy in the months of January – February.

I also assumed that the Portland Hydro Project would be renewed. The Portland Hydro Project, which consists of approximately 33 MW of run-of-river hydro capacity on the Bull Run River, was assumed to be extended and was reflected in rates in Docket No. UE 308, the 2017 Annual Power Cost Update Tariff filing. Thus, it is appropriately included in the load and resource balance in the IRP.

<u>Renewable Resources</u>

From the Company's load and resource balance, it is not clear what capacity contribution values were assumed for wind and solar resources. ICNU was hopeful that—following Docket UM 1719, an Investigation to Explore Issus Related to a Renewable Generator's Contribution to Capacity—the IRP would report capacity contribution values based upon the Effective Load Carrying Capability methodology. Notwithstanding, ICNU was unable to identify in the IRP where the Company calculated the contribution to peak of these resources. Absent the analysis, and based on my experience, my analysis assumes a 10% capacity contribution for wind and a 20% capacity contribution for solar. I request that the Company provide further information regarding the capacity contribution of wind and solar resources in its Reply Comments.

Distributed Solar

While the Company's load and resource balance included approximately 118 MW of capacity for non-renewable distributed generation, including the Dispatchable Stand-by Generation program, it appears to have excluded any contribution to peak associated with the approximate 65 MW of distributed solar resources included in the IRP.[7/] My analysis includes a provision for capacity provided by distributed solar resources as an offset to load in the load and resource balance detailed in Confidential Attachment A.

Gas Plants Capacity

The Company appears to have slightly understated capacity available from gas resources. Based on capability in the month of January, my analysis based on the Company's most recently filed MONET model shows a slightly greater amount of capacity available from gas plants, than the 1,810 MW assumed in the Company's load and resource balance. While I have not necessarily reconciled the difference, it may be that the Company has measured the capability of gas plants in a different month of the year. In my opinion, January is the most appropriate month to measure nameplate capacity of gas plants because the Company load typically peaks when weather is coldest. In fact, it is possible that the use of average January temperatures may actually understate the capacity from gas plants because the average is not representative of the coldest hours in the month, when the Company is peaking.

In summary, based on the above analysis, existing resources will provide the Company with reasonable resource adequacy at least until the retirement of Boardman at the end of 2020. Consistent with the results of the Council's Seventh Plan, I 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; and, 3) continue to review demand-side options as alternatives to physical resource acquisition.

III. PORTFOLIO ANALYSIS

In addition to the problems associated with the use of the RECAP model, I believe that the portfolio analysis in the 2016 IRP is also based upon a methodology that is fundamentally flawed. Other utilities use models, such as PacifiCorp's System Optimizer model, to develop least-cost portfolios given a set of inputs. These type of models are designed to optimize the type and timing of resource additions in each portfolio for purposes of satisfying peak load requirements.

The Company's analysis, however, 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

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[7/] 2016 IRP, Volume II, Appendix D, at 384 preselected portfolio was the lowest cost. This type of analysis, however, does not necessarily reflect an optimal resource portfolio, unless one believes that the Company preselected the optimal resource portfolio. As I demonstrate below, the portfolios preselected by the Company are not optimal, particularly considering the resource need discussed in the prior section.

Similarly, the Company's attempt to consider the risk of portfolios is also analytically flawed. A risk analysis can only be said to be reasonable if it reflects a reasonable distribution of likely outcomes. While the Company considers some outcomes—such as a high gas price scenario—it did not consider portfolio performance under other potential outcomes.

Faced with these deficiencies in portfolio modeling, it is difficult to analyze the reasonableness of any aspect of the Company's proposed action plan. Notwithstanding, I have attempted to work within the Company's scenario analysis framework, using the AURORAxmp model, in order to try to determine the portfolio actions that the Company might take in order to best satisfy its potential capacity needs in coming years.

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

One purpose of the IRP is to determine the lowest cost resources to acquire, as well as the proper timing of such acquisitions. This often results in complex trade-offs between various baseload, peaker, storage, and market resources. Yet the Company's approach of evaluating portfolios is based on a limited number of pre-defined portfolios that fails to provide an adequate answer to this question of resource type and timing.

In Attachment B, I have constructed a simple Excel model that builds resource portfolios based on the load and resource table provided in Attachment A. The analysis assumes that all capacity shortfalls, after accounting for market purchases and other new resources, must be met by a combined cycle combustion turbine ("CCCT"), as a last resort. Based on this analysis, I was able to test whether it is less costly to acquire other types of resources or to rely more heavily on market purchases. I also prepared some sensitivities surrounding RPS compliance. These portfolios were input into a reference case scenario in AURORAxmp, and the resulting portfolio costs were considered in a net present value revenue requirement analysis. The results of that analysis are detailed in Table 2, below.

TABLE 2
AURORAxmp Portfolio Sensitivities (2018 – 2037)
Present Value Revenue Requirement ($000) Deltas from Portfolio 1
Reference Gas, No Carbon Constraint

		10-year PVRR	Delta	20-year PVRR	Delta
Portfolio 1	Base Case (2021 Combined Cycle Combustion Turbine)	10,836,781	-	20,639,777	-
Portfolio 2	Low Market Capacity	10,865,208	28,427	20,670,108	30,331
Portfolio 3	High Market Capacity	10,576,839	(259,942)	20,135,192	(504,584)
Portfolio 4	Wells Not Extended	10,896,214	59,432	20,875,291	235,515
Portfolio 5	Simple Cycle Combustion Turbine 2021	10,812,003	(24,778)	20,555,660	(84,117)
Portfolio 6	150 MW Direct Access	10,662,544	(174,238)	20,206,268	(433,509)
Portfolio 7	RPS Early Action (515 MW Wind 2018)	11,147,303	310,522	21,111,530	471,753
Portfolio 8	No Unbundled Renewable Energy Certificates	10,910,010	73,229	20,922,906	283,129
Portfolio 9	No Renewable Portfolio Standard	10,779,267	(57,514)	20,124,937	(514,839)
Portfolio 0	Company Preferred: Efficient Capacity 2021	11,418,357	581,576	21,689,254	1,049,478

Several interesting things can be discerned from the AURORAxmp runs detailed above. While I plan to present a fuller portfolio analysis in Final Comments, below are some of my preliminary conclusions.

- The base portfolio (Portfolio 1) in my analysis is approximately $1.0 billion less expensive, on a 20-year present value revenue requirement basis, than the Company's preferred portfolio (Portfolio 0). Thus, the Company's proposal for 850 MW of traditional capacity and 515 MW of renewable capacity could result in substantial and unnecessary costs to ratepayers.

- Portfolio 3—a portfolio which assumes 700 MW of market capacity is available to the Company—is the lowest cost portfolio. This indicates that it is crucial for the Company and the Commission to consider the amount of capacity available from the Mid-Columbia and COB markets, prior to pursuing physical resource acquisition.

- Portfolio 6 indicates that there are significant capacity benefits to remaining customers if 150 MW of load were to migrate to direct access and permanently opt-out of cost of service rates. Such a portfolio could defer the need to acquire a physical resource until 2025, saving ratepayers $433.5 million on a 20-year net present value revenue requirement basis.

- Portfolio 5 indicates that, if physical capacity is truly required in 2021, it would be more cost effective to ratepayers to acquire a smaller, Simple Cycle Combustion Turbine ("SCCT"), rather than a larger, CCCT. Ratepayers save $84.1 million in a portfolio that includes a 2021 SCCT, delaying the need to build a larger, CCCT until at least 2025.

- Portfolio 7 cost ratepayers $471.8 million more on a 20-year net present value revenue requirement basis than the base portfolio, indicating it is not a least cost strategy to pursue early action of an RPS resource at this time.

These conclusions contradict many of the conclusions reached by the Company in its IRP. These conclusions also indicate that it could cost ratepayers substantially, and unnecessarily, if the Company is to pursue the supply-side actions to acquire 850 MW of traditional capacity and 515 MW of renewable capacity. For that reason, I do not agree that the Company is justified in pursuing those supply-side actions. While the Company may be justified in acquiring a smaller, SCCT resource in 2021, the economics of that strategy are contingent on the level of market capacity actually available, as well as potential opportunities for large customers to opt out of cost of service rates. These options must be understood before a resource decision can be made.

2. Large Customer Opt-Out Should be Considered as a Resource Option

The Company assumes that no customers will elect to opt out of cost of service rates in the study period. Yet, if a large customer were to opt out of cost of service rates, it may allow the Company to avoid acquiring expensive capacity and renewable resources. Based on the portfolio analysis conducted above, ratepayers would save approximately $433.5 million, on a 20-year net present value revenue requirement basis, if 150 MW of additional load were to elect to opt out of cost of service rates. Given this potential savings, the Company should consider options that provide proper economic signals to, and eliminate barriers for, large customers who may be interested in opting out of cost of service rates. The current transition adjustment methodology, which focuses solely on short-term marginal costs, 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. Prior to building a new resource, the Company should 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.

3. A 34-year Planning Period is Too Long

When performing the above scenarios, I limited the planning period to 20 years. A 34-year planning period is too long and puts too much weight on speculative assumptions about distant future conditions to be used for planning. The Commission's IRP guidelines do not require an analysis beyond 20 years.

Moreover, the proposed 34-year planning period is considerably longer than the 20-year planning period used in the Company's 2013 IRP. While such a long study period may present some useful information, modeling portfolio performance that far into the future is problematic and the costs of distant resources should not form the basis for near-term resource acquisitions. Resource decisions often involve a trade-off between paying more rates today, in order to achieve dispatch savings expected over a long period of time.

Forecasting conditions far into the future is inherently speculative. Ten years ago, when the Company issued the 2006 IRP for example, there was no contemplation of the rapid expansion of the Energy Imbalance Market ("EIM") throughout the West. If one goes back even further, 34 years ago to 1982, the utilities were not even contemplating the liquid bilateral markets that are ubiquitous today. The concept of something such as the EIM would have been outside of the range of any future possibility in 1982. A lot can change over a ten-year period, let alone the 34-year planning period proposed by the Company, and for that reason it makes sense to place less weight on benefits and costs expected far into the future. For purposes of making resource decisions today, a twenty-year planning period is sufficient to make informed resource decisions that form the basis for the Company's action plan. Additionally, I also gave greater weight to the first ten years of the analysis in order to reflect the greater certainty of cost predictions over this period. Thus, in the above table I also calculated levelized portfolio costs over a 10-year period, as a metric used to benchmark against 20-year results.

4. The Company's Risk Analysis is Analytically Improper

While the Company attempts to evaluate the risk profile of various portfolios, it does not properly evaluate risk. Stochastic modeling is typically used to evaluate risk associated with a resource portfolio. The aim of this type of modeling is to change model inputs based upon a distribution of expected outcomes. The Company, however, did not use a distribution of expected outcomes, and rather, relies on a skewed set of scenarios that do not properly reflect a balanced set of possibilities.

This can be noted by the failure of the Company to model a low natural gas price scenario. In addition to modeling median and "high" gas price scenarios, the Company needs to model a "low" natural gas price scenario. As noted in Figure 3.8, the Company models natural gas prices based on a reference case and a high natural gas price scenario, both of which assume prices will increase considerably in the study period. The Company, however, does not model any scenario to evaluate the impact of the very real possibility that natural gas prices will continue to remain low into the future.

The omission of a low gas price scenario is, in my opinion, a critical analytical flaw in the Company's IRP risk analysis. The exclusion of a low gas price scenario is problematic primarily because it skews the Company's risk modeling, in favor of a future state that is based on high gas prices. If one only includes two future natural gas states, a reference gas price state and a high gas price state, the median outcome of the risk modeling will be representative of prices that are between the reference state and the high gas state. That is, if only a high and reference gas prices are used, the reference case is no longer the median outcome. Thus, if a high price scenario is to be used, at a minimum, a low price scenario also needs to be modeled in order to maintain the reference case as a median outcome.

5. The Company Appears to Double Count Carbon Costs in AURORA

The Company develops a carbon price for its reference case scenario based on a report prepared by Synapse Energy Economics. The Synapse report estimates carbon costs based on the price of allowances under a mass-based state implementation plan with the new source complement. The Company notes, however, that this is not its preferred implementation plan because a source-level rate based implementation plan would result in no incremental cost to customers.

In addition to modeling carbon costs directly in AURORAxmp, however, it appears that the Company has also established a region-wide cap on carbon emissions as a constraint in the model. While not necessarily opposed to understanding the impact of potential carbon costs on portfolios, modeling a carbon price, as well as a carbon cap, did not seem to be a consistent way to model potential carbon costs. I request that the Company provide further information about how it has modeled these costs in its Reply Comments.

In addition, the Company currently expects to comply with the Clean Power Plan at no incremental cost to customers. Accordingly, the reference case should assume zero carbon costs to the Company, at least through the Clean Power Plan compliance period. In modeling prices in the AURORAxmp model, it may be appropriate to model carbon costs in the reference case forward price curve in regions where the Clean Power Plan is expected to impose additional costs. However, assigning an incremental carbon cost to the Company’s portfolio in the reference case contradicts my understanding of how compliance with the Clean Power Plan might impact customers of the Company.

For these reasons, the above scenarios were analyzed in a case with zero carbon costs, though I am interested in evaluating the sensitivity of those portfolios to carbon costs in its Final Comments.

IV. RENEWABLE PORTFOLIO STANDARDS COMPLIANCE

Based upon the portfolio analysis detailed in Table 2 above, I disagree the Company is justified in pursuing early action of a renewable resource. My analysis demonstrates that early action will ultimately cost ratepayers $471.8 million on a net present value revenue requirement basis over a 20-year period. Over a 10-year period, early action will cost ratepayer approximately $310.5 million on a present value revenue requirement basis. Thus, a just-in-time RPS resource acquisition strategy is a less costly strategy—and as discussed below, a less risky strategy—for complying with RPS requirements.

1. The Company Should Adopt a Just-in-Time Acquisition Strategy for RPS Resources, Delaying RPS Resource Action Until 2030

ICNU continues to support a "just-in-time" acquisition strategy for RPS resources, including utilization of unbundled Renewable Energy Certificates ("RECs") up to the 20% statutory maximum level. Consequently, I have several concerns with the Company's proposal for early action with respect to renewable resource additions in the IRP. Not only does the Company's early-action proposal disregard a number of costs and risks associated with building a renewable resource prior to the time that such a resource is needed, an early-action strategy should not be considered in isolation from 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.

While 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. Additionally, the long-term rate savings should be far more certain to occur than suggested in the Company's analysis.

Moreover, early-action strategies also rely on long-term resource and planning assumptions, which carry significant forecasting risk for customers. For example, if solar costs continue on their current trajectory, the Company may be placed in a situation where it is considerably less expensive to acquire renewable energy ten years from now, than it is today. Similarly, if PTCs are ultimately extended, an early-action strategy could also cost ratepayers greatly. The rapid pace of technological change in the energy industry today creates a significant risk that acquiring new generation, renewable or otherwise, before it is needed will impose substantial stranded costs on customers.

2. The Company Should Assume that the Use of Unbundled RECs Will Delay the Need for New RPS Additions until 2030

As noted in Docket No. UM 1773, if the Company continues to rely on unbundled RECs, it will not need to acquire a new RPS resource until 2030. In the IRP, the Company attempts to model a scenario that relies on unbundled RECs to meet 20% of its RPS requirements. That portfolio, titled "Efficient Capacity 2021 20% Unbundled RECs," however, only assumes that an RPS resource can be delayed until 2025. This is because the Company assumed it could only rely on unbundled RECs over the period 2016 through 2021.

Given the low price of unbundled RECs and the Company's history of relying on unbundled RECs to meet 20% of its RPS obligation to date, it would be more appropriate for the Company to assume that it can rely on unbundled RECs over the entire IRP study period, which should delay the physical compliance need until 2030, while maintaining a sufficient REC bank balance. This analysis has been provided in Attachment C. For purposes of the portfolio analysis detailed above, I assumed that the Company could acquire RECs at a nominal levelized price of $10/MWh. Based on my analysis, the nominal levelized REC price would have to exceed $32.75/MWh (the "tipping point") before it became more economic to acquire a physical resource.

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

As also noted in Docket No. UM 1773, the Company currently lacks sufficient taxable income necessary to utilize all of the production tax credits generated from the Biglow Canyon and Tucannon River Wind facilities. While unused production tax credits can be "carried-forward" to be used on a future tax return, the growing balances have presented ratemaking concerns. Specifically, the Company has historically argued that it should be allowed to earn a return on the carry-forward balances at its full cost of capital.

The growth in the Company's production tax credit carry-forward balance was expected to slow, and potentially reverse, when the production tax credits generated from the Biglow Canyon facility begin to expire over the period 2018 through 2020. If the Company acquires a 515 MW wind resource in 2018, however, the growth in the carry-forward balance will not slow, but rather, will begin to accelerate at a problematic rate. As demonstrated in Attachment E, for example, I forecast that the production tax credit carry-forward balance is expected to grow to in excess of $400 million if the Company acquires a 515 MW wind facility in 2018. I also demonstrate that the return on this balance could cost ratepayers approximately $233.0 million on a present value revenue requirement basis. This additional cost has been reflected in the cost associated with an early-action strategy in the portfolio analyses detailed in Table 2, above.

The Company's portfolio analysis, however, has made no effort to quantify the impacts on rates associated with these tax attributes in the IRP. In the scenarios that rely on an early-action strategy, the Company includes no additional cost associated with its inability to utilize production tax credits on its tax return, which consequently overstates the benefits of early action to acquire the full value of the production tax credit. Given the level of risk associated with an early-action strategy, all costs and risks must be accounted for in the Company's analysis, including the cost of production tax credit 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, there are still fundamental questions that need to be considered before taking the supply side resource actions proposed by the Company.

With respect to the renewable resource addition, I disagree with the economic analysis proposed by the Company to justify the 515 MW of near-term renewable resources, as my analysis demonstrates that it will not be beneficial to ratepayers to pursue an early-action strategy at this time.

In addition, the Company's proposal for approximately 850 MW of supply-side capacity resources should also not be acknowledged, as the Company has not justified such a substantial need at this time. Given the smaller magnitude of the capacity need demonstrated by my analysis—and the potential that the Company may be able to avoid the need altogether through existing market capability or other demand-side alternatives—my recommendation is 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

Bradley Mullins
Consultant, Energy & Utilities
333 SW Taylor Street, Suite 400
Portland, Oregon 97204

Attachment A contains Protected Information subject to Order No. 16-408 and has been redacted in its entirety.

Attachment B
Resource Portfolios, Winter Peak, 2017 - 2037
Comments of Brad Mullins On Behalf of ICNU
LC 66 - Portland General Electric Company 2016 Integrated Resource Plan

Portfolio 1 - Base Case (2021 Combined Cycle Combustion Turbine)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Resources																				
Coal	809	809	809	296	296	296	296	296	296	296	296	296	296	296	296	296	296	-	-	-
Natural Gas	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851
Hydroelectric	804	804	804	804	804	804	804	584	584	584	574	574	574	574	574	574	574	574	574	574
Renewable Resources	84	84	84	84	84	84	84	84	84	84	81	81	81	81	81	81	81	81	74	73
Qualifying Facilities	82	82	82	82	82	82	82	82	82	82	82	82	82	82	81	81	81	81	81	81
Seasonal Contracts	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Existing Rsrcs.	**3,730**	**3,730**	**3,630**	**3,117**	**3,117**	**3,117**	**3,117**	**2,897**	**2,897**	**2,897**	**2,885**	**2,885**	**2,885**	**2,885**	**2,883**	**2,883**	**2,883**	**2,587**	**2,580**	**2,579**
Net Load + PRM	**3,633**	**3,645**	**3,611**	**3,660**	**3,671**	**3,686**	**3,705**	**3,729**	**3,762**	**3,796**	**3,832**	**3,867**	**3,904**	**3,943**	**3,983**	**4,024**	**4,065**	**4,108**	**4,153**	**4,200**
Net Position (No New Rsrcs)	**97**	**85**	**18**	**(543)**	**(554)**	**(569)**	**(588)**	**(831)**	**(864)**	**(899)**	**(947)**	**(982)**	**(1,019)**	**(1,058)**	**(1,099)**	**(1,141)**	**(1,182)**	**(1,520)**	**(1,573)**	**(1,620)**
New Resources (Cont. to Peak)																				
Douglas Wells Ext.	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Front Office Trans.	-	-	-	-	-	3	23	266	299	-	-	16	-	-	16	57	99	-	2	49
Direct Acces Opt-out	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable Rsrcs	-	-	-	-	-	-	-	-	-	-	-	-	118	118	118	118	118	206	206	206
SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCCT	-	-	-	400	400	400	400	400	400	800	800	800	800	800	800	800	800	1,200	1,200	1,200
Total New Resources	**166**	**166**	**166**	**566**	**566**	**569**	**588**	**831**	**864**	**966**	**966**	**982**	**1,083**	**1,083**	**1,099**	**1,141**	**1,182**	**1,572**	**1,573**	**1,620**
Net Position (w/ New Rsrcs)	**262**	**251**	**184**	**22**	**12**	**-**	**-**	**-**	**-**	**67**	**19**	**-**	**65**	**26**	**-**	**-**	**-**	**51**	**-**	**-**

Attachment B
Resource Portfolios, Winter Peak, 2017 - 2037
Comments of Brad Mullins On Behalf of ICNU
LC 66 - Portland General Electric Company 2016 Integrated Resource Plan

Portfolio 2 - Low Market Capacity

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Resources																				
Coal	809	809	809	296	296	296	296	296	296	296	296	296	296	296	296	296	296	-	-	-
Natural Gas	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851
Hydroelectric	804	804	804	804	804	804	804	584	584	584	574	574	574	574	574	574	574	574	574	574
Renewable Resources	84	84	84	84	84	84	84	84	84	84	81	81	81	81	81	81	81	81	74	73
Qualifying Facilities	82	82	82	82	82	82	82	82	82	82	82	82	82	82	81	81	81	81	81	81
Seasonal Contracts	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Existing Rsrcs.	**3,730**	**3,730**	**3,630**	**3,117**	**3,117**	**3,117**	**3,117**	**2,897**	**2,897**	**2,897**	**2,885**	**2,885**	**2,885**	**2,885**	**2,883**	**2,883**	**2,883**	**2,587**	**2,580**	**2,579**
Net Load + PRM	**3,633**	**3,645**	**3,611**	**3,660**	**3,671**	**3,686**	**3,705**	**3,729**	**3,762**	**3,796**	**3,832**	**3,867**	**3,904**	**3,943**	**3,983**	**4,024**	**4,065**	**4,108**	**4,153**	**4,200**
Net Position (No New Rsrcs)	**97**	**85**	**18**	**(543)**	**(554)**	**(569)**	**(588)**	**(831)**	**(864)**	**(899)**	**(947)**	**(982)**	**(1,019)**	**(1,058)**	**(1,099)**	**(1,141)**	**(1,182)**	**(1,520)**	**(1,573)**	**(1,620)**
New Resources (Cont. to Peak)																				
Douglas Wells Ext.	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Front Office Trans.	-	-	-	-	-	3	23	266	-	-	-	16	-	-	16	57	99	-	2	49
Direct Acces Opt-out	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable Rsrcs	-	-	-	-	-	-	-	-	-	-	-	-	118	118	118	118	118	206	206	206
SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCCT	-	-	-	400	400	400	400	400	800	800	800	800	800	800	800	800	800	1,200	1,200	1,200
Total New Resources	**166**	**166**	**166**	**566**	**566**	**569**	**588**	**831**	**966**	**966**	**966**	**982**	**1,083**	**1,083**	**1,099**	**1,141**	**1,182**	**1,572**	**1,573**	**1,620**
Net Position (w/ New Rsrcs)	**262**	**251**	**184**	**22**	**12**	**-**	**-**	**-**	**101**	**67**	**19**	**-**	**65**	**26**	**-**	**-**	**-**	**51**	**-**	**-**

Attachment B
Resource Portfolios, Winter Peak, 2017 - 2037
Comments of Brad Mullins On Behalf of ICNU
LC 66 - Portland General Electric Company 2016 Integrated Resource Plan

Portfolio 3 - High Market Capacity

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Resources																				
Coal	809	809	809	296	296	296	296	296	296	296	296	296	296	296	296	296	296	-	-	-
Natural Gas	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851
Hydroelectric	804	804	804	804	804	804	804	584	584	584	574	574	574	574	574	574	574	574	574	574
Renewable Resources	84	84	84	84	84	84	84	84	84	84	81	81	81	81	81	81	81	81	74	73
Qualifying Facilities	82	82	82	82	82	82	82	82	82	82	82	82	82	82	81	81	81	81	81	81
Seasonal Contracts	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Existing Rsrcs.	**3,730**	**3,730**	**3,630**	**3,117**	**3,117**	**3,117**	**3,117**	**2,897**	**2,897**	**2,897**	**2,885**	**2,885**	**2,885**	**2,885**	**2,883**	**2,883**	**2,883**	**2,587**	**2,580**	**2,579**
Net Load + PRM	**3,633**	**3,645**	**3,611**	**3,660**	**3,671**	**3,686**	**3,705**	**3,729**	**3,762**	**3,796**	**3,832**	**3,867**	**3,904**	**3,943**	**3,983**	**4,024**	**4,065**	**4,108**	**4,153**	**4,200**
Net Position (No New Rsrcs)	**97**	**85**	**18**	**(543)**	**(554)**	**(569)**	**(588)**	**(831)**	**(864)**	**(899)**	**(947)**	**(982)**	**(1,019)**	**(1,058)**	**(1,099)**	**(1,141)**	**(1,182)**	**(1,520)**	**(1,573)**	**(1,620)**
New Resources (Cont. to Peak)																				
Douglas Wells Ext.	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Front Office Trans.	-	-	-	378	388	403	423	666	699	733	781	416	735	774	416	457	499	749	402	449
Direct Acces Opt-out	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable Rsrcs	-	-	-	-	-	-	-	-	-	-	-	-	118	118	118	118	118	206	206	206
SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCCT	-	-	-	-	-	-	-	-	-	-	-	400	-	-	400	400	400	400	800	800
Total New Resources	**166**	**166**	**166**	**543**	**554**	**569**	**588**	**831**	**864**	**899**	**947**	**982**	**1,019**	**1,058**	**1,099**	**1,141**	**1,182**	**1,520**	**1,573**	**1,620**
Net Position (w/ New Rsrcs)	**262**	**251**	**184**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Attachment B
Resource Portfolios, Winter Peak, 2017 - 2037
Comments of Brad Mullins On Behalf of ICNU
LC 66 - Portland General Electric Company 2016 Integrated Resource Plan

Portfolio 4 - Wells Not Extended

	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Resources																				
Coal	809	809	809	296	296	296	296	296	296	296	296	296	296	296	296	296	296	-	-	-
Natural Gas	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851
Hydroelectric	804	804	804	804	804	804	804	584	584	584	574	574	574	574	574	574	574	574	574	574
Renewable Resources	84	84	84	84	84	84	84	84	84	84	81	81	81	81	81	81	81	81	74	73
Qualifying Facilities	82	82	82	82	82	82	82	82	82	82	82	82	82	82	81	81	81	81	81	81
Seasonal Contracts	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Existing Rsrcs.	**3,730**	**3,730**	**3,630**	**3,117**	**3,117**	**3,117**	**3,117**	**2,897**	**2,897**	**2,897**	**2,885**	**2,885**	**2,885**	**2,885**	**2,883**	**2,883**	**2,883**	**2,587**	**2,580**	**2,579**
Net Load + PRM	**3,633**	**3,645**	**3,611**	**3,660**	**3,671**	**3,686**	**3,705**	**3,729**	**3,762**	**3,796**	**3,832**	**3,867**	**3,904**	**3,943**	**3,983**	**4,024**	**4,065**	**4,108**	**4,153**	**4,200**
Net Position (No New Rsrcs)	**97**	**85**	**18**	**(543)**	**(554)**	**(569)**	**(588)**	**(831)**	**(864)**	**(899)**	**(947)**	**(982)**	**(1,019)**	**(1,058)**	**(1,099)**	**(1,141)**	**(1,182)**	**(1,520)**	**(1,573)**	**(1,620)**
New Resources (Cont. to Peak)																				
Douglas Wells Ext.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Front Office Trans.	-	-	-	143	154	169	188	31	64	99	147	182	101	140	182	223	264	114	167	214
Direct Acces Opt-out	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable Rsrcs	-	-	-	-	-	-	-	-	-	-	-	-	118	118	118	118	118	206	206	206
SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCCT	-	-	-	400	400	400	400	800	800	800	800	800	800	800	800	800	800	1,200	1,200	1,200
Total New Resources	**-**	**-**	**-**	**543**	**554**	**569**	**588**	**831**	**864**	**899**	**947**	**982**	**1,019**	**1,058**	**1,099**	**1,141**	**1,182**	**1,520**	**1,573**	**1,620**
Net Position (w/ New Rsrcs)	**97**	**85**	**18**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Attachment B
Resource Portfolios, Winter Peak, 2017 - 2037
Comments of Brad Mullins On Behalf of ICNU
LC 66 - Portland General Electric Company 2016 Integrated Resource Plan

Portfolio 5 - Simple Cycle Combustion Turbine 2021

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Resources																				
Coal	809	809	809	296	296	296	296	296	296	296	296	296	296	296	296	296	296	-	-	-
Natural Gas	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851
Hydroelectric	804	804	804	804	804	804	804	584	584	584	574	574	574	574	574	574	574	574	574	574
Renewable Resources	84	84	84	84	84	84	84	84	84	84	81	81	81	81	81	81	81	81	74	73
Qualifying Facilities	82	82	82	82	82	82	82	82	82	82	82	82	82	82	81	81	81	81	81	81
Seasonal Contracts	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Existing Rsrcs.	**3,730**	**3,730**	**3,630**	**3,117**	**3,117**	**3,117**	**3,117**	**2,897**	**2,897**	**2,897**	**2,885**	**2,885**	**2,885**	**2,885**	**2,883**	**2,883**	**2,883**	**2,587**	**2,580**	**2,579**
Net Load + PRM	**3,633**	**3,645**	**3,611**	**3,660**	**3,671**	**3,686**	**3,705**	**3,729**	**3,762**	**3,796**	**3,832**	**3,867**	**3,904**	**3,943**	**3,983**	**4,024**	**4,065**	**4,108**	**4,153**	**4,200**
Net Position (No New Rsrcs)	**97**	**85**	**18**	**(543)**	**(554)**	**(569)**	**(588)**	**(831)**	**(864)**	**(899)**	**(947)**	**(982)**	**(1,019)**	**(1,058)**	**(1,099)**	**(1,141)**	**(1,182)**	**(1,520)**	**(1,573)**	**(1,620)**
New Resources (Cont. to Peak)																				
Douglas Wells Ext.	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Front Office Trans.	-	-	-	148	158	173	193	36	69	103	151	186	105	144	186	227	269	119	172	219
Direct Acces Opt-out	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable Rsrcs	-	-	-	-	-	-	-	-	-	-	-	-	118	118	118	118	118	206	206	206
SCCT	-	-	-	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230
CCCT	-	-	-	-	-	-	-	400	400	400	400	400	400	400	400	400	400	800	800	800
Total New Resources	**166**	**166**	**166**	**543**	**554**	**569**	**588**	**831**	**864**	**899**	**947**	**982**	**1,019**	**1,058**	**1,099**	**1,141**	**1,182**	**1,520**	**1,573**	**1,620**
Net Position (w/ New Rsrcs)	**262**	**251**	**184**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Attachment B
Resource Portfolios, Winter Peak, 2017 - 2037
Comments of Brad Mullins On Behalf of ICNU
LC 66 - Portland General Electric Company 2016 Integrated Resource Plan

Portfolio 6 - 150 MW Direct Access

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Resources																				
Coal	809	809	809	296	296	296	296	296	296	296	296	296	296	296	296	296	296	-	-	-
Natural Gas	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851
Hydroelectric	804	804	804	804	804	804	804	584	584	584	574	574	574	574	574	574	574	574	574	574
Renewable Resources	84	84	84	84	84	84	84	84	84	84	81	81	81	81	81	81	81	81	74	73
Qualifying Facilities	82	82	82	82	82	82	82	82	82	82	82	82	82	82	81	81	81	81	81	81
Seasonal Contracts	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Existing Rsrcs.	**3,730**	**3,730**	**3,630**	**3,117**	**3,117**	**3,117**	**3,117**	**2,897**	**2,897**	**2,897**	**2,885**	**2,885**	**2,885**	**2,885**	**2,883**	**2,883**	**2,883**	**2,587**	**2,580**	**2,579**
Net Load + PRM	**3,633**	**3,645**	**3,611**	**3,660**	**3,671**	**3,686**	**3,705**	**3,729**	**3,762**	**3,796**	**3,832**	**3,867**	**3,904**	**3,943**	**3,983**	**4,024**	**4,065**	**4,108**	**4,153**	**4,200**
Net Position (No New Rsrcs)	**97**	**85**	**18**	**(543)**	**(554)**	**(569)**	**(588)**	**(831)**	**(864)**	**(899)**	**(947)**	**(982)**	**(1,019)**	**(1,058)**	**(1,099)**	**(1,141)**	**(1,182)**	**(1,520)**	**(1,573)**	**(1,620)**
New Resources (Cont. to Peak)																				
Douglas Wells Ext.	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Front Office Trans.	-	-	-	228	238	253	273	116	149	183	231	266	185	224	266	-	-	199	252	299
Direct Acces Opt-out	-	-	-	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
Renewable Rsrcs	-	-	-	-	-	-	-	-	-	-	-	-	118	118	118	118	118	206	206	206
SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCCT	-	-	-	-	-	-	-	400	400	400	400	400	400	400	400	800	800	800	800	800
Total New Resources	**166**	**166**	**166**	**543**	**554**	**569**	**588**	**831**	**864**	**899**	**947**	**982**	**1,019**	**1,058**	**1,099**	**1,233**	**1,233**	**1,520**	**1,573**	**1,620**
Net Position (w/ New Rsrcs)	**262**	**251**	**184**	-	-	-	-	-	-	-	-	-	-	-	-	**93**	**51**	-	-	-

Attachment B
Resource Portfolios, Winter Peak, 2017 - 2037
Comments of Brad Mullins On Behalf of ICNU
LC 66 - Portland General Electric Company 2016 Integrated Resource Plan

Portfolio 7 - RPS Early Action (515 MW Wind 2018)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Resources																				
Coal	809	809	809	296	296	296	296	296	296	296	296	296	296	296	296	296	296	-	-	-
Natural Gas	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851
Hydroelectric	804	804	804	804	804	804	804	584	584	584	574	574	574	574	574	574	574	574	574	574
Renewable Resources	84	84	84	84	84	84	84	84	84	84	81	81	81	81	81	81	81	81	74	73
Qualifying Facilities	82	82	82	82	82	82	82	82	82	82	82	82	82	82	81	81	81	81	81	81
Seasonal Contracts	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Existing Rsrcs.	**3,730**	**3,730**	**3,630**	**3,117**	**3,117**	**3,117**	**3,117**	**2,897**	**2,897**	**2,897**	**2,885**	**2,885**	**2,885**	**2,885**	**2,883**	**2,883**	**2,883**	**2,587**	**2,580**	**2,579**
Net Load + PRM	**3,633**	**3,645**	**3,611**	**3,660**	**3,671**	**3,686**	**3,705**	**3,729**	**3,762**	**3,796**	**3,832**	**3,867**	**3,904**	**3,943**	**3,983**	**4,024**	**4,065**	**4,108**	**4,153**	**4,200**
Net Position (No New Rsrcs)	**97**	**85**	**18**	**(543)**	**(554)**	**(569)**	**(588)**	**(831)**	**(864)**	**(899)**	**(947)**	**(982)**	**(1,019)**	**(1,058)**	**(1,099)**	**(1,141)**	**(1,182)**	**(1,520)**	**(1,573)**	**(1,620)**
New Resources (Cont. to Peak)																				
Douglas Wells Ext.	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Front Office Trans.	-	-	-	-	-	-	5	244	277	-	-	-	27	66	108	149	191	69	122	169
Direct Acces Opt-out	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable Rsrcs	18	18	18	18	18	18	18	21	21	21	21	21	26	26	26	26	26	85	85	85
SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCCT	-	-	-	400	400	400	400	400	400	800	800	800	800	800	800	800	800	1,200	1,200	1,200
Total New Resources	**183**	**183**	**183**	**583**	**583**	**583**	**588**	**831**	**864**	**987**	**987**	**987**	**1,019**	**1,058**	**1,099**	**1,141**	**1,182**	**1,520**	**1,573**	**1,620**
Net Position (w/ New Rsrcs)	**280**	**268**	**202**	**40**	**29**	**14**	**-**	**-**	**-**	**88**	**40**	**5**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Attachment B
Resource Portfolios, Winter Peak, 2017 - 2037
Comments of Brad Mullins On Behalf of ICNU
LC 66 - Portland General Electric Company 2016 Integrated Resource Plan

Portfolio 8 - No Unbundled Renewable Energy Certificates

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Resources																				
Coal	809	809	809	296	296	296	296	296	296	296	296	296	296	296	296	296	296	-	-	-
Natural Gas	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851
Hydroelectric	804	804	804	804	804	804	804	584	584	584	574	574	574	574	574	574	574	574	574	574
Renewable Resources	84	84	84	84	84	84	84	84	84	84	81	81	81	81	81	81	81	81	74	73
Qualifying Facilities	82	82	82	82	82	82	82	82	82	82	82	82	82	82	81	81	81	81	81	81
Seasonal Contracts	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Existing Rsrcs.	**3,730**	**3,730**	**3,630**	**3,117**	**3,117**	**3,117**	**3,117**	**2,897**	**2,897**	**2,897**	**2,885**	**2,885**	**2,885**	**2,885**	**2,883**	**2,883**	**2,883**	**2,587**	**2,580**	**2,579**
Net Load + PRM	**3,633**	**3,645**	**3,611**	**3,660**	**3,671**	**3,686**	**3,705**	**3,729**	**3,762**	**3,796**	**3,832**	**3,867**	**3,904**	**3,943**	**3,983**	**4,024**	**4,065**	**4,108**	**4,153**	**4,200**
Net Position (No New Rsrcs)	**97**	**85**	**18**	**(543)**	**(554)**	**(569)**	**(588)**	**(831)**	**(864)**	**(899)**	**(947)**	**(982)**	**(1,019)**	**(1,058)**	**(1,099)**	**(1,141)**	**(1,182)**	**(1,520)**	**(1,573)**	**(1,620)**
New Resources (Cont. to Peak)																				
Douglas Wells Ext.	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Front Office Trans.	-	-	-	-	-	3	23	266	196	230	278	-	277	-	-	-	40	290	-	-
Direct Acces Opt-out	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable Rsrcs	-	-	-	-	-	-	-	-	103	103	103	103	176	176	176	176	176	265	265	265
SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCCT	-	-	-	400	400	400	400	400	400	400	400	800	400	800	800	800	800	800	1,200	1,200
Total New Resources	**166**	**166**	**166**	**566**	**566**	**569**	**588**	**831**	**864**	**899**	**947**	**1,069**	**1,019**	**1,142**	**1,142**	**1,142**	**1,182**	**1,520**	**1,630**	**1,630**
Net Position (w/ New Rsrcs)	**262**	**251**	**184**	**22**	**12**	**-**	**-**	**-**	**-**	**-**	**-**	**86**	**-**	**84**	**43**	**2**	**-**	**-**	**57**	**10**

Attachment B
Resource Portfolios, Winter Peak, 2017 - 2037
Comments of Brad Mullins On Behalf of ICNU
LC 66 - Portland General Electric Company 2016 Integrated Resource Plan

Portfolio 9 - No Renewable Portfolio Standard

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Resources																				
Coal	809	809	809	296	296	296	296	296	296	296	296	296	296	296	296	296	296	-	-	-
Natural Gas	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851
Hydroelectric	804	804	804	804	804	804	804	584	584	584	574	574	574	574	574	574	574	574	574	574
Renewable Resources	84	84	84	84	84	84	84	84	84	84	81	81	81	81	81	81	81	81	74	73
Qualifying Facilities	82	82	82	82	82	82	82	82	82	82	82	82	82	82	81	81	81	81	81	81
Seasonal Contracts	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Existing Rsrcs.	**3,730**	**3,730**	**3,630**	**3,117**	**3,117**	**3,117**	**3,117**	**2,897**	**2,897**	**2,897**	**2,885**	**2,885**	**2,885**	**2,885**	**2,883**	**2,883**	**2,883**	**2,587**	**2,580**	**2,579**
Net Load + PRM	**3,633**	**3,645**	**3,611**	**3,660**	**3,671**	**3,686**	**3,705**	**3,729**	**3,762**	**3,796**	**3,832**	**3,867**	**3,904**	**3,943**	**3,983**	**4,024**	**4,065**	**4,108**	**4,153**	**4,200**
Net Position (No New Rsrcs)	**97**	**85**	**18**	**(543)**	**(554)**	**(569)**	**(588)**	**(831)**	**(864)**	**(899)**	**(947)**	**(982)**	**(1,019)**	**(1,058)**	**(1,099)**	**(1,141)**	**(1,182)**	**(1,520)**	**(1,573)**	**(1,620)**
New Resources (Cont. to Peak)																				
Douglas Wells Ext.	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Front Office Trans.	-	-	-	-	-	3	23	266	299	-	-	16	53	92	134	175	216	155	208	255
Direct Acces Opt-out	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable Rsrcs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCCT	-	-	-	400	400	400	400	400	400	800	800	800	800	800	800	800	800	1,200	1,200	1,200
Total New Resources	**166**	**166**	**166**	**566**	**566**	**569**	**588**	**831**	**864**	**966**	**966**	**982**	**1,019**	**1,058**	**1,099**	**1,141**	**1,182**	**1,520**	**1,573**	**1,620**
Net Position (w/ New Rsrcs)	**262**	**251**	**184**	**22**	**12**	**-**	**-**	**-**	**-**	**67**	**19**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Attachment B
Resource Portfolios, Winter Peak, 2017 - 2037
Comments of Brad Mullins On Behalf of ICNU
LC 66 - Portland General Electric Company 2016 Integrated Resource Plan

Portfolio 0 - Company Preferred: Efficient Capacity 2021

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Resources																				
Coal	809	809	809	296	296	296	296	296	296	296	296	296	296	296	296	296	296	-	-	-
Natural Gas	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851
Hydroelectric	804	804	804	804	804	804	804	584	584	584	574	574	574	574	574	574	574	574	574	574
Renewable Resources	84	84	84	84	84	84	84	84	84	84	81	81	81	81	81	81	81	81	74	73
Qualifying Facilities	82	82	82	82	82	82	82	82	82	82	82	82	82	82	81	81	81	81	81	81
Seasonal Contracts	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Existing Rsrcs.	**3,730**	**3,730**	**3,630**	**3,117**	**3,117**	**3,117**	**3,117**	**2,897**	**2,897**	**2,897**	**2,885**	**2,885**	**2,885**	**2,885**	**2,883**	**2,883**	**2,883**	**2,587**	**2,580**	**2,579**
Net Load + PRM	**3,633**	**3,645**	**3,611**	**3,660**	**3,671**	**3,686**	**3,705**	**3,729**	**3,762**	**3,796**	**3,832**	**3,867**	**3,904**	**3,943**	**3,983**	**4,024**	**4,065**	**4,108**	**4,153**	**4,200**
Net Position (No New Rsrcs)	**97**	**85**	**18**	**(543)**	**(554)**	**(569)**	**(588)**	**(831)**	**(864)**	**(899)**	**(947)**	**(982)**	**(1,019)**	**(1,058)**	**(1,099)**	**(1,141)**	**(1,182)**	**(1,520)**	**(1,573)**	**(1,620)**
New Resources (Cont. to Peak)																				
Douglas Wells Ext.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Front Office Trans.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Direct Acces Opt-out	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable Rsrcs	18	18	18	18	18	18	18	21	21	21	21	21	26	26	26	26	26	85	85	85
SCCT	290	318	318	386	396	411	432	697	722	758	801	844	877	917	979	1,022	1,081	1,310	1,310	1,310
CCCT	-	-	-	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388
Total New Resources	**308**	**335**	**335**	**791**	**801**	**816**	**838**	**1,107**	**1,132**	**1,167**	**1,210**	**1,253**	**1,290**	**1,330**	**1,392**	**1,436**	**1,494**	**1,784**	**1,784**	**1,784**
Net Position (w/ New Rsrcs)	**405**	**420**	**354**	**248**	**248**	**247**	**249**	**275**	**267**	**268**	**264**	**271**	**272**	**272**	**293**	**295**	**313**	**263**	**210**	**163**

ATTACHMENT C (Page 1 of 3)

SCHEDULE OF FORECAST RENEWABLE ENERGY CERTIFICATE ("REC") BALANCES, JIT RESOURCE ACQUISITION

Assuming unbundled RECs <u>are</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) = ∑ (b):(d) - (e)	
2016	894	336	62		308	984	
2017	984	336	62		309	1,073	
2018	1,073	336	62		310	1,161	
2019	1,161	336	62		312	1,248	
2020	1,248	348	83		417	1,262	
2021	1,262	348	85		424	1,271	
2022	1,271	348	86		429	1,276	
2023	1,276	348	87		434	1,276	
2024	1,276	348	88		439	1,273	
2025	1,273	348	120		600	1,141	
2026	1,141	348	129		646	972	
2027	972	348	138		691	767	
2028	767	347	147		737	525	
2029	525	340	156		782	238	
2030	*238*	*339*	*166*	*400*	*828*	*315*	*Resource Need*
2031	315	339	178	400	889	343	*Deficit Year*
2032	343	331	190	400	951	313	
2033	313	328	202	400	1,012	231	
2034	231	328	215	400	1,074	100	
2035	100	328	227	700	1,135	220	
2036	220	303	239	700	1,196	266	
2037	266	302	252	700	1,258	261	

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) = ∑ (b):(d) - (e)
2016	894	336	62		308	984
2017	984	336	62		309	1,073
2018	1,073	336	62	515	310	1,676
2019	1,676	336	62	515	312	2,277
2020	2,277	348	83	515	417	2,806
2021	2,806	348	85	515	424	3,330
2022	3,330	348	86	515	429	3,849
2023	3,849	348	87	515	434	4,365
2024	4,365	348	88	515	439	4,876
2025	4,876	348	120	628	600	5,372
2026	5,372	348	129	628	646	5,831
2027	5,831	348	138	628	691	6,253
2028	6,253	347	147	628	737	6,638
2029	6,638	340	156	628	782	6,980
2030	6,980	339	166	755	828	7,412
2031	7,412	339	178	755	889	7,795
2032	7,795	331	190	755	951	8,121
2033	8,121	328	202	755	1,012	8,394
2034	8,394	328	215	755	1,074	8,618
2035	8,618	328	227	2,511	1,135	10,548
2036	10,548	303	239	2,511	1,196	12,405
2037	12,405	302	252	2,511	1,258	14,211

ATTACHMENT C (Page 3 of 3)
SCHEDULE OF FORECAST RENEWABLE ENERGY CERTIFICATE ("REC") BALANCES, JIT RESOURCE ACQUISITION
Assuming unbundled RECs are not 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) = ∑ (b):(d) - (e)	
2016	894	336	62		308	984	
2017	984	336	-		309	1,011	
2018	1,011	336	-		310	1,037	
2019	1,037	336	-		312	1,062	
2020	1,062	348	-		417	993	
2021	993	348	-		424	917	
2022	917	348	-		429	836	
2023	836	348	-		434	749	
2024	749	348	-		439	658	
2025	658	348	-		600	406	
2026	*406*	*348*	*-*	*350*	*646*	*459*	*Resource Need*
2027	459	348	-	350	691	465	*Deficit Year*
2028	465	347	-	350	737	425	
2029	425	340	-	350	782	332	
2030	332	339	-	600	828	444	
2031	444	339	-	600	889	494	
2032	494	331	-	600	951	474	
2033	474	328	-	600	1,012	389	
2034	389	328	-	600	1,074	244	
2035	244	328	-	900	1,135	336	
2036	336	303	-	900	1,196	342	
2037	342	302	-	900	1,258	286	

Attachment D
Portfolio Net Present Value Revenue Requirement Calculation ($000) Reference Gas, Reference Load, No Carbon
Comments of Brad Mullins On Behalf of ICNU
LC 66 - Portland General Electric Company 2016 Integrated Resource Plan

	Portfolio 0	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5	Portfolio 6	Portfolio 7	Portfolio 8	Portfolio 9
Year	Company Preferred: Efficient Capacity 2021	Base Case (2021 Combined Cycle Combustion Turbine)	Low Market Capacity	High Market Capacity	Wells Not Extended	Simple Cycle Combustion Turbine 2021	150 MW Direct Access	RPS Early Action (515 MW Wind 2018)	No Unbundled Renewable Energy Certificates	No Renewable Portfolio Standard
2018	1,244,646	1,174,465	1,174,465	1,174,465	1,174,465	1,174,465	1,149,984	1,211,798	1,169,034	1,169,034
2019	1,298,153	1,228,169	1,228,169	1,228,169	1,228,169	1,228,169	1,202,474	1,264,971	1,222,703	1,222,703
2020	1,376,495	1,303,429	1,303,429	1,303,429	1,303,429	1,303,429	1,276,777	1,346,357	1,296,123	1,296,123
2021	1,417,914	1,330,830	1,330,830	1,273,790	1,330,830	1,304,405	1,244,989	1,383,653	1,323,402	1,323,402
2022	1,595,921	1,530,893	1,530,893	1,485,995	1,530,893	1,516,993	1,440,620	1,563,458	1,523,377	1,523,377
2023	1,672,898	1,606,339	1,606,339	1,560,674	1,606,339	1,592,410	1,511,409	1,641,358	1,598,735	1,598,735
2024	1,752,392	1,688,046	1,688,046	1,635,826	1,688,046	1,668,385	1,583,937	1,720,833	1,680,354	1,680,354
2025	1,838,874	1,713,763	1,713,763	1,662,235	1,763,141	1,744,741	1,655,951	1,772,818	1,703,251	1,703,251
2026	1,910,243	1,798,391	1,846,795	1,747,370	1,847,233	1,829,988	1,736,335	1,843,052	1,896,723	1,787,080
2027	1,985,700	1,903,723	1,904,212	1,804,641	1,904,657	1,887,963	1,791,617	1,963,785	2,013,855	1,891,613
2028	2,155,681	2,008,787	2,009,227	1,902,380	2,009,681	1,990,149	1,888,537	2,127,937	2,111,767	1,995,878
2029	2,223,298	2,068,142	2,068,590	2,015,466	2,117,053	2,052,894	1,947,331	2,180,726	2,164,868	2,054,434
2030	2,308,131	2,257,641	2,258,098	2,201,142	2,310,291	2,239,372	2,130,486	2,258,102	2,301,919	2,126,349
2031	2,436,871	2,377,703	2,378,169	2,325,121	2,426,359	2,363,894	2,248,752	2,371,080	2,426,330	2,234,502
2032	2,535,843	2,462,797	2,463,273	2,408,043	2,513,534	2,447,850	2,329,327	2,454,668	2,508,009	2,323,216
2033	2,647,878	2,552,964	2,553,448	2,502,254	2,599,591	2,542,754	2,417,115	2,549,032	2,586,738	2,433,047
2034	2,781,036	2,676,907	2,677,412	2,622,115	2,727,509	2,663,470	2,533,033	2,669,413	2,710,118	2,554,904
2035	2,969,817	2,799,121	2,799,625	2,743,190	2,850,802	2,785,463	2,600,735	2,860,956	2,828,103	2,611,420
2036	3,088,285	2,914,055	2,914,571	2,855,305	2,968,421	2,898,527	2,708,053	2,976,413	2,946,819	2,708,347
2037	3,156,916	2,984,705	2,985,229	2,928,690	3,036,281	2,972,492	2,778,371	3,032,821	3,002,116	2,827,950
NPVRR 10 Year	11,418,357	10,836,781	10,865,208	10,576,839	10,896,214	10,812,003	10,662,544	11,147,303	10,910,010	10,779,267
Levelized 10 Year	1,566,418	1,486,635	1,490,534	1,450,975	1,494,788	1,483,236	1,462,732	1,529,233	1,496,681	1,478,745
NPVRR 20 year	21,689,254	20,639,777	20,670,108	20,135,192	20,875,291	20,555,660	20,206,268	21,111,530	20,922,906	20,124,937
Levelized 20 year	1,922,404	1,829,385	1,832,073	1,784,661	1,850,259	1,821,929	1,790,961	1,871,198	1,854,479	1,783,752
Discount Rate	6.20%									

SCHEDULE OF FORECAST PRODUCTION TAX CREDIT CARRYFORWARD BALANCES

Including a 500 MW wind addition in 2018

Year	PTC Rate	Beg. Balance	Generated: Biglow 1	Biglow 2	Biglow 3	Tucannon	500 MW	**Total**	Utilized	**End Balance**	**Approx Rev. Req.**
2016	23.00	42,427,293	8,216,663	10,400,403	9,086,819	21,446,402		**49,150,287**	31,516,720	**60,060,860**	**6,392,469**
2017	23.00	60,060,860	8,216,663	10,400,403	9,086,819	21,446,402		**49,150,287**	31,516,720	**77,694,427**	**8,269,266**
2018	23.46	77,694,427		10,400,403	9,268,556	21,875,330	35,964,180	**77,508,468**	31,516,720	**123,686,174**	**13,164,314**
2019	23.93	123,686,174			9,643,005	22,759,093	36,683,464	**69,085,562**	31,516,720	**161,255,016**	**17,162,886**
2020	24.41	161,255,016				24,152,132	37,417,133	**61,569,265**	31,516,720	**191,307,561**	**20,361,474**
2021	24.90	191,307,561				26,143,044	38,165,476	**64,308,520**	31,516,720	**224,099,360**	**23,851,610**
2022	25.39	224,099,360				28,864,033	38,928,785	**67,792,818**	31,516,720	**260,375,458**	**27,712,590**
2023	25.90	260,375,458				32,505,590	39,707,361	**72,212,950**	31,516,720	**301,071,688**	**32,044,020**
2024	26.42	301,071,688				37,338,705	40,501,508	**77,840,213**	31,516,720	**347,395,181**	**36,974,377**
2025	26.95	347,395,181				43,748,244	41,311,538	**85,059,782**	31,516,720	**400,938,243**	**42,673,136**
2026	27.49	400,938,243					42,137,769	**42,137,769**	31,516,720	**411,559,291**	**43,803,568**
2027	28.04	411,559,291					42,980,524	**42,980,524**	31,516,720	**423,023,095**	**45,023,697**
2028	28.60	423,023,095						-	31,516,720	**391,506,375**	**41,669,272**
2029	29.17	391,506,375						-	31,516,720	**359,989,655**	**38,314,847**
2030	29.75	359,989,655						-	31,516,720	**328,472,934**	**34,960,422**
2031	30.35	328,472,934						-	31,516,720	**296,956,214**	**31,605,997**
2032	30.95	296,956,214						-	31,516,720	**265,439,494**	**28,251,572**
2033	31.57	265,439,494						-	31,516,720	**233,922,773**	**24,897,147**
2034	32.21	233,922,773						-	31,516,720	**202,406,053**	**21,542,722**
2035	32.85	202,406,053						-	31,516,720	**170,889,333**	**18,188,297**
2036	33.51	170,889,333						-	31,516,720	**139,372,613**	**14,833,872**
2037	34.18	139,372,613						-	31,516,720	**107,855,892**	**11,479,447**
2038	34.86	107,855,892						-	31,516,720	**76,339,172**	**8,125,022**
2039	35.56	76,339,172						-	31,516,720	**44,822,452**	**4,770,596**
2040	36.27	44,822,452						-	31,516,720	**13,305,731**	**1,416,171**
2041	36.99	13,305,731						-	13,305,731	-	-
										2018 Present Value Rev. Req. (2015$)	287,547,318
										Incremental PVRR from 500 MW Wind	232,973,995

SCHEDULE OF FORECAST PRODUCTION TAX CREDIT CARRYFORWARD BALANCES

Without a near-term wind addition

			Generated:							
Year	PTC Rate	Beg. Balance	Biglow 1	Biglow 2	Biglow 3	Tucannon	**Total**	Utilized	**End Balance**	**Approx Rev. Req.**
2016	23.00	42,427,293	8,216,663	10,400,403	9,086,819	21,446,402	**49,150,287**	31,516,720	**60,060,860**	**6,392,469**
2017	23.00	60,060,860	8,216,663	10,400,403	9,086,819	21,446,402	**49,150,287**	31,516,720	**77,694,427**	**8,269,266**
2018	23.46	77,694,427		10,400,403	9,268,556	21,875,330	**41,544,288**	31,516,720	**87,721,994**	**9,336,532**
2019	23.93	87,721,994			9,643,005	22,759,093	**32,402,099**	31,516,720	**88,607,373**	**9,430,765**
2020	24.41	88,607,373				24,152,132	**24,152,132**	31,516,720	**81,242,784**	**8,646,929**
2021	24.90	81,242,784				26,143,044	**26,143,044**	31,516,720	**75,869,108**	**8,074,991**
2022	25.39	75,869,108				28,864,033	**28,864,033**	31,516,720	**73,216,421**	**7,792,657**
2023	25.90	73,216,421				32,505,590	**32,505,590**	31,516,720	**74,205,291**	**7,897,906**
2024	26.42	74,205,291				37,338,705	**37,338,705**	31,516,720	**80,027,275**	**8,517,558**
2025	26.95	80,027,275				43,748,244	**43,748,244**	31,516,720	**92,258,799**	**9,819,398**
2026	27.49	92,258,799					-	31,516,720	**60,742,078**	**6,464,973**
2027	28.04	60,742,078					-	31,516,720	**29,225,358**	**3,110,548**
2028	28.60	29,225,358					-	29,225,358	-	-
2029	29.17	-					-	-	-	-
2030	29.75	-					-	-	-	-
2031	30.35	-					-	-	-	-
2032	30.95	-					-	-	-	-
2033	31.57	-					-	-	-	-
2034	32.21	-					-	-	-	-
2035	32.85	-					-	-	-	-
2036	33.51	-					-	-	-	-
2037	34.18	-					-	-	-	-
2038	34.86	-					-	-	-	-
2039	35.56	-					-	-	-	-
2040	36.27	-					-	-	-	-
									2018 Present Value Rev. Req. (2015$)	54,573,323