Attachment

Pacific Power & Light Company 2017 Integrated Resource Plan
Docket UE-160353

I. Introduction

RCW 19.280.030 and WAC 480-100-238 direct investor-owned energy companies (IOUs) to develop an integrated resource plan (IRP) every two years. The IRP, or plan must identify "the mix of energy supply resources and conservation that will meet current and future needs at the lowest reasonable cost to the utilities and its ratepayers."[1] The IRP touches every aspect of a company's operations and provides essential public participation opportunities for stakeholders to assist in the development of an effective plan. In preparing an IRP, utilities are required to consider changes and trends in energy markets, resource costs, cost of risks associated with greenhouse gas emissions, state and federal regulatory requirements, and other shifts in the policy and market landscape.[2] The statute and the Commission's rule require that IOUs conduct a comprehensive analysis of the costs, benefits, and risks of various approaches to meeting future resource needs using commercially available information. The intent is for each regulated utility to develop a strategic approach that fits its unique situation, while minimizing risks and costs for the company and its ratepayers.

The Washington Utilities and Transportation Commission (Commission) recognizes and appreciates the efforts of Pacific Power and Light Company's (Pacific Power or Company) to navigate a carbon regulatory environment that has proven hard to predict. The shifting status of the Clean Power Plan (CPP) made this planning cycle challenging. The Commission also appreciates the Company's thoughtful consideration of its many options with regard to Regional Haze compliance. Though we have concerns regarding the stepwise nature of the IRP modeling process, and do not agree with some of the assumptions that Pacific Power has incorporated into its models, we hope that the Company will continue to develop and refine its models as states develop their implementation plans and the Company's compliance obligations become clearer.

The Commission determines that Pacific Power's 2017 IRP complies with the statute and rules governing IRPs, but recommends the Company address several areas for improvement in developing its next IRP. In the following sections, we provide comments on the 2017 IRP and identify specific areas for improvement for the 2019 IRP.

[1] WAC 480-100-238(2)(a); see also RCW 19.280.020(9).
[2] RCW 19.280.020(11); WAC 480-100-238(2)(b).

II. Summary of 2017 Electric Integrated Resource Plan

Pacific Power projects its Washington service territory to experience negative load growth of -0.03 percent annually between 2017 and 2026,[3] but peak load is projected to grow in the western side of its system at 0.05 percent in the summer and 0.09 percent in the winter over the 20-year planning horizon.[4] As a single system, Pacific Power's projections of the rate of growth in total energy demand and peak demand are lower relative to the 2015 IRP and the 2015 IRP update, which the Company primarily attributes to reduced industrial loads and continued gains in conservation.[5]

The biggest change from the 2015 to 2017 IRP is the Company's decision to pursue significant wind resources in the near term. Pacific Power contends that, because repowered and new wind resources qualify for a production tax credit, acquiring these resources will lower the cost and risk of the total portfolio. In addition, the Company reviewed its approach to complying with Regional Haze requirements, accelerating the retirement dates for some of its coal-fired generation assets. The 2017 Plan also significantly increases the Company's use of front office transactions and demand response. Table 1 compares the preferred portfolio identified in the 2017 IRP with the 2015 IRP portfolio.

[3] Pacific Power 2017 IRP, Vol. 2, p. 16, Table A.10. Load growth calculations net of demand side management.
[4] Pacific Power 2017 IRP, Vol. 1, p. 91 and 92. Figures calculated by Commission staff based on data in Tables 5.14 and 5.15. load growth calculations net of demand side management.
[5] Pacific Power 2017 IRP, Vol.1 , p. 3.

Table 1. Pacific Power's preferred portfolios: differences between the 2015 IRP and 2017 IRP [6]

	2015 IRP Portfolio Changes	2017 IRP Portfolio Changes
Generation : Supply-side resources		
2017		
2018	Reitre Naughton 3 (280 MW); add 337 MW gas repower	
2019		Retire Naughton 3 (280 MW)
2020		
2021		Retire Cholla 4 (387 MW); add 1100 MW wind
2022		
2023		
2024		
2025	Convert Cholla 4 from coal to gas	
2026		Retire Craig 1 (82 MW)
2027		
2028	Retire Dave Johnson units 1-4 (762 MW); add 423 MW CCCT	Retire Dave Johnson units 1-4 (762 MW)
2029		Retire Jim Bridger 1 (354); add SCCT (200 MW); add 97 MW solar
2030	Retire Huntington 2 (450 MW), and Naughton 1, 2 (357 MW), and gas repower (337 MW); add 1159 MW CCCT	Retire Naughton 1, 2 (156, 201 MW); add 436 MW CCCT
2031	Retire Hayden 1, 2 (78 MW)	Retire Hayden 1, 2 (45, 33 MW); add 85 MW wind, 117 MW solar
2032		Add 237 MW solar
2033	Retire Hunter 2 (269 MW) and Gatsby 1-6 (358 MW); add 635 MW CCCT	Retire Gadsby 1-6 (358 MW); add 477 MW CCCT, 200 MW SCCT, 226 MW solar
2034	Add 635 MW CCCT	Add 49 MW solar
2035		Retire Craig 2 (82 MW); add 291 MW solar
2036		Add 774 MW wind
Total generation for 20-year cycle:	Coal: (3,163 MW) Natural gas: 3,239 MW Wind: 0 MW Solar: 7 MW	Coal: (3,099 MW) Natural gas: 913 MW Wind: 1,959 MW Solar: 1,040 MW
Demand Side : DSM 1 - Demand response; DSM 2 - Energy efficiency/Conservation		
first 10 years	20.5 MW DSM 1; 1,429 MW DSM 2	0 MW DSM 1; 1,229 MW DSM 2
second 10 years	21.2 MW DSM 1; 1,250 MW DSM 2	365.3 MW DSM 1; 848 MW DSM 2
Total DSM:	41.7 MW DSM 1; 2,679 MW DSM 2	365.3 MW DSM 1; 2,077 MW DSM 2
Front Office Transactions : Spot market purchases packaged into energy and capacity resources		
first 10 years	Annual average of 843 MW	Annual average of 1,128 MW
second 10 years	Annual average of 1,123 MW	Annual average of 2,004 MW
Total FOT:	Annual average of 983 MW	Annual average of 1,556 MW

III. Comments and Modeling Improvements

Commission staff and other stakeholders have communicated to the Commission that the Company did not share the timing and nature of the Wyoming wind and transmission project decisions with the advisory group in a timely manner. The Company did not offer any details on the projects, which

[6] Data from 2015 IRP, Vol. 1, p. 196 and 2017 IRP, Vol.1 , p. 244. Figures do not sum perfectly due to the exclusion of years 2015 and 2016, and the inclusion of small resources in generation summaries.

entailed a substantial reorientation of the IRP's focus, until months after the internal decision to pursue the projects was made, late in the IRP process and without vetting by the advisory group. We are disappointed to see that Pacific Power's commitments to transparency and inclusiveness with the advisory group were not met, and encourage the Company to refocus on conducting its resource planning activities in that spirit.

Generally, the Commission is pleased with the thorough presentation of the Company's analyses in the 2017 IRP. As with the 2015 IRP, we appreciate the Company's inclusion of extensive data disks with the filing.

The Commission also appreciates the Company's new conservation potential assessment, as well as the description of how lowered projections for energy costs influence the amount of cost-effective conservation. We note that the 2017 IRP shows that projected energy growth in its west balancing authority (BA) is more than offset by energy efficiency through 2024, and commend the Company for its continued commitment to conservation as a cost- and risk-reducing resource.

a. Colstrip and Jim Bridger

Two of Pacific Power's remaining coal-fuel generation facilities remain in Washington's Western Control Area allocation. Jim Bridger is a 2,121 MW plant in Wyoming completed in 1979. Pacific Power also owns 10 percent of each of Colstrip Units 3 & 4, which were built in the mid-1980s.

As part of its 2015 IRP, Pacific Power performed an in-depth analysis of the economics of a select group of its coal generation facilities.[7] Since that time, changing demand and market forces have fundamentally altered the dispatch and economics of Jim Bridger and Colstrip.[8] Furthermore, by 2030 Pacific Power will no longer be able to dispatch Colstrip and its other coal generating plants to serve Oregon load or charge Oregon ratepayers for its expenses for these plants, even though Oregon is one of its largest customer bases.[9] As such, continued investment in the plant's operation must be continuously reviewed.

We are deeply concerned with the direct costs of continued operation of its coal-fueled resources and the magnitude of economic risk of continued investment in those units. Pacific Power's IRP does not explicitly identify or discuss the risks faced by the utility and its ratepayers, including the costs of risks associated with the coal plants' fuel source, projected capital investments, and ongoing operational expenses, or cost shifts to Washington customers when the Company must remove coal generation expense from Oregon rates.

As part of its 2019 IRP, Pacific Power must undertake a complete examination of costs of continued operation and investment into Colstrip Units 3 & 4 and the Jim Bridger plant. For Jim Bridger, in addition to the applicable questions asked concerning Colstrip below, the examination should include:

[7] Docket UE-140546.
[8] For example, the demand for energy and capacity has slowed, and market prices for energy have declined due to a drop in natural gas prices and a buildout of renewable resources in the Western Interconnection.
[9] Oregon Clean Electricity & Clean Transition Law, https://www.pacificpower.net/env/oregon-clean-energy/oregon-law-details.html.

1. What are the market alternatives to continued operation of the Rosebud mine?
2. How do the risks of continued operation of the Rosebud mine compare to purchasing coal in the market?
3. Using the price of coal from the Rosebud mine, how does the economic dispatch of Jim Bridger compare to market prices for electricity in the Western Interconnection?
4. Could the Jim Bridger plant obtain sufficient fuel to dispatch during the utility's winter peak without the coal supply from the Rosebud mine?

Regarding Colstrip Units 3 & 4, the Commission expects Pacific Power to answer the following questions in its 2019 IRP:

1. Regarding fuel source cost and risk:
   a. How dependent is Colstrip on a single-source mine for its fuel?
   b. How well understood is the supply of coal from the Colstrip mine?
      i. What are the financial risks of the type of mining used to extract the existing coal?
      ii. As the need for fuel for Colstrip declines, how does the cost per unit of coal from the Colstrip mine increase?
      iii. What are the counter-party risk of mine operation?
      iv. What risks to coal supply and coal cost does the Joint Colstrip ownership agreement impose? How will Pacific Power manage them?
   c. How does the fuel supply risk from Colstrip compare to that of natural gas?
2. Does Pacific Power have an assessment of the cost related to the counter-party risk of Riverstone ceasing operation of its share of Colstrip Units 3?[10] If not, why not?
3. Does Pacific Power have an assessment of the cost of the counter-party risk of Riverstone being financially unable or otherwise failing to pay its share of decommissioning and remediation costs for Units 3?
4. What are the economics of the high-cost scenario under a "low gas" scenario forecast?
5. How are the economics of the Colstrip Units 3 & 4 affected if natural gas prices continue to remain relatively flat?
6. What are Pacific Power's best estimates of remediation and decommissioning costs associated with Colstrip Units 3 & 4?
7. Has the Company quantified capacity replacement costs for Colstrip Units 3 or 4 that it could use as a basis of seeking replacement capacity as an alternative to any large capital investments it faces at Colstrip?
8. What is the risk of the failure of a large cost component of Colstrip Units 3 or 4 (such as: the heat exchangers, steam turbine or drive shafts) over Pacific Power's expected 20-year life of the plant?

The economic viability of Jim Bridger and Colstrip Units 3 & 4 are dependent on the outcome of numerous future events. To properly capture the expected cost over the 20-year horizon of the Plan, the probability of each event needs to be assessed and the cost weighted by its probability of occurrence. This comprehensive approach produces a probability distribution for the set of possible total cost outcomes of the operation of a plant over the planning horizon. The Commission recognizes that the approach taken to achieve this analysis may vary; however, regardless of the approach used,

[10] Riverstone purchased the assets of Talon Energy.

each utility's resource plan must comprehensively assess all categories of cost and risk, particularly for complex resources like its coal-fueled plants that are included in the Plan.

In its next IRP, Pacific Power should assess all categories of operational costs for Jim Bridger and Colstrip Units 3 & 4 and explicitly identify the range of possible costs in each category over the expected life of the plants. Pacific Power should also identify whether the costs are known or if they are open-ended. If costs are not known and measurable, the risk that such unknowns add to the utility portfolio should be identified by modeling a range of possible costs or other suitable means. As appropriate, the probability needs to be assessed and the cost weighted by its probability of occurrence. The Company's 2019 Plan should clearly and transparently identify cost data and discuss in detail the relationship between the range of these input assumptions, portfolio modeling logic, and the output of the modeling, as well as how the Company used such analysis to choose its expected case.

b. Balancing Area (BA) Analysis

In acknowledging Pacific Power's 2013 IRP, the Commission requested that the Company model its east and west BAs separately in the 2015 IRP.[11] We expressed a concern that the Company's system-level approach to modeling failed to account for the differences in load growth and resource base between the two areas and may be resulting in portfolios that do not optimally meet the individual needs of each BA. In acknowledging the 2015 IRP, we did not accept the S-10 sensitivity as a satisfactory response to our request, and requested another study be done which more transparently optimized the portfolio for the Western Control Area (WCA), and which either correlated with the power flow details provided in other proceedings, or explained any differences.[12]

Pacific Power responded to the Commission's request by including the East/West Split Sensitivity as a part of its analysis.[13] We appreciate the Company's responsiveness and incremental improvements to this modeling process in the 2017 IRP. The sensitivity provided some useful information and presents a more accurate cost comparison on WCA terms. However, a number of questions remain. We are particularly interested in gaining a better understanding of how and why the model is making the resource decisions that it makes in the WCA sensitivity, as some of the outcomes seem counterintuitive. We encourage the Company to continue working with Staff to ensure that the model is accurately portraying the benefits of system integration and that Staff understands the model's operations.

The Company presents the cost impacts of the preferred portfolio on a system basis. The 2017 IRP fits with the pattern of previous IRPs in projecting that the WCA's load growth and peak demand growth after conservation are flat or very close to flat, while the Eastern Control Area (ECA) of Pacific Power's system is projected to continue experiencing robust growth. But the purpose of the Commission's request is not to see how much the WCA portfolio would cost if the ECA were not present; it is a means of quantifying the benefits of system integration to each individual BA.

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[11] Docket UE-120416, Pacific Power & Light Company 2013 IRP Acknowledgment Letter Attachment (Nov. 25, 2013) at p. 5-6.
[12] Docket UE-140546, Pacific Power & Light Company 2015 IRP Acknowledgment Letter Attachment (Nov. 13, 2015) at p. 5-6.
[13] 2017 IRP, Vol. 1, p. 258-9.

Accordingly, we again ask that a WCA stand-alone analysis be completed that shows the cost impacts at the BA level. This request implies a stand-alone analysis of the ECA, and a robust description of the modeling interaction between the two discrete systems, i.e. discrete within this modeling exercise.

As we have stated in prior acknowledgement letters, the Commission does not necessarily disagree with the Company's system-wide approach to resource planning, and recognizes that such an approach may offer integration benefits that reduce costs for all of the Company's customers. But we cannot accept such a significant assumption on its face; the system-wide plan must be accompanied by a counterfactual analysis that provides a check by identifying the costs of a BA approach. We therefore request that in addition to addressing the concerns mentioned above, the Company incorporate the BA analysis in all future IRPs.

c. Wind Repowering, New Wind and Energy Gateway West

Public Process: Like many other stakeholders participating in Pacific Power's IRP public process, Commission staff were surprised by the Company's proposal to pursue new wind resources and repower much of its wind generation facilities, which was presented at the final General Public Meeting on March 2017. We are concerned about the lack of timely communication of this change in direction. The Company's decision to make investments to qualify for the safe harbor provisions of the wind production tax credits (PTC) was made in December 2016, but stakeholders remained uninformed of the Company's decision and subsequent shift in the IRP's direction until the final General Public Meeting. There has been no clear explanation for why the Company decided to withhold this information during the January 2017 meeting. We request that the Company provide this in this current IRP docket. While the Commission understands the time-sensitive nature of the Company's decision to act on an expiring opportunity, the lack of communication on this issue is troubling – especially given the Company's expectation that all participants sign and abide by its non-disclosure agreement.

Repowered Wind: While the Company's analysis of the repowered wind proposal forecasts that the decision would be beneficial within the IRP's 20-year planning horizon, much of the justification for the repowering plan is the stream of benefits created by "resetting the clock" on the useful lives of the Company's wind resources. The Commission has concerns about forecasting streams of benefits beyond the IRP's planning horizon. We note that decisions made based on projections into such a remote future are inherently tenuous, especially when those decisions derive benefit primarily by attempting to beat projected power prices.

New ECA Wind and Associated Transmission: The Company's selected portfolio includes very large investments in new wind resources in the Eastern Control Area (ECA). The portfolio was selected based on modeled savings relative to other alternatives, but these savings represent about 0.6 percent of the portfolio's total present value revenue requirement (PVRR). These margins are not substantial enough to be the sole justification for multi-billion dollar investments, and projected over 20 years they seem unacceptably risky. This is particularly true when the acquisitions are being made solely for economic reasons based on the Company's assumptions.

We appreciate the Company's voluntary, informational filing of applicable RFP documentation to this docket. This should make any potential review of these acquisitions easier for the Commission, Staff and the Company.

d. Energy Storage

In its acknowledgment of the Company's 2015 IRP, the Commission identified a number of benefits of energy storage not contemplated in the main analysis of the 2015 IRP, and encouraged Pacific Power to expand the scope of its energy storage study in the 2017 IRP. We requested that the 2017 study quantify the ancillary benefits of energy storage and identify specific opportunities for energy storage projects on Pacific Power's system, both at the transmission and distribution levels. While we appreciate the Company's recognition "that there are stacked benefits from storage systems,"[14] it appears that the modeling tools used in the 2017 IRP were still not capable of identifying and assigning value to those benefits, nor to easily and more directly compare energy storage with more traditional resources. The Company instead performed some sensitivities around batteries and compressed air storage using its traditional tools, and mentioned that evaluation of energy storage projects is done on a case-by-case basis.

We recognize that the Commission issued its policy statement on energy storage several months after Pacific Power filed its 2017 IRP, and that the Company had limited guidance for the treatment of energy storage in that planning cycle. However, now that the Commission has issue its policy statement, we expect that the Company will include its principles when developing the 2019 IRP.

e. Demand Response

We commend the Company for identifying in the 2015 IRP an irrigation load control pilot in the west BA as an action item, and are pleased to see that the program is operating in Oregon.[15] We also appreciate that demand response has been represented in this IRP analysis as a resource that is directly competitive with other resources, both to meet peak load and to comply with carbon regulations.

While we recognize that the selected portfolio is optimized to be least-cost and least-risk, we are nonetheless concerned about the mismatch between the Company's preferred portfolio and the Northwest Power and Conservation Council's (Council) conclusion in its Seventh Northwest Power Plan. The Company's portfolio would add no DSM Class 1 resources to its western BA until 2028, but the Council contends that significant demand response resources are needed in the region by 2021 to meet additional winter peaking capacity.[16] Our concern is exacerbated by Pacific Power's reliance on market purchases to meet peak load, as the risk of any regional peak demand shortages falls most heavily on utilities that are reliant on the market.

f. Resource Adequacy Analysis

In its 2013 IRP acknowledgment letter, the Commission asked for an analysis of the risks inherent in the Company's substantial reliance on market resources. The resulting evaluation in the 2015 IRP did

[14] 2017 IRP, Vol. 1, p. 255.
[15] 2017 IRP Vol. 1, p. 271.
[16] Northwest Power and Conservation Council, Seventh Northwest Power Plan, at 1-6.

not capture these risks. In the 2015 acknowledgment letter, we again asked the Company to include a market reliance risk assessment in the 2017 IRP as a condition to granting the Company's RFP waiver request in Docket UE-151694.

We find that the Company's 2017 market reliance risk assessment is substantively similar to its 2015 assessment, and vulnerable to the same criticisms. The assessment essentially reviews two studies – a power supply assessment from the Western Electricity Coordinating Council (WECC), and the Council's Pacific Northwest Power Supply Adequacy Assessment for 2021. While the Company presents these studies as market risk assessments, the Company does not perform any assessment of the risks inherent in relying on the market. The WECC's assessment concludes that available power supply will be adequate to meet demand on a WECC-wide basis for many years; the Council's assessment concludes that regional power supply will be adequate until 2020. The Company's assessment does not synthesize these reports' conclusions, and lacks explanation for how or why power supply sufficiency on a WECC level protects Pacific Power customers from shortages at the regional level.

The assessment also lacks any quantitative analysis of the risk identified by the Council and acknowledged by the Company. The Council's power supply assessments have consistently identified the early 2020s as the timeframe for a shift in the regional market. Given Pacific Power's long-term reliance on Mid-Columbia market purchases, it is imperative that the Company understand the risks it faces as many regional plant retirements draw nearer. We again request that the Company provide a market reliance risk assessment in the 2019 IRP, and expect that this analysis will result in a quantified representation of risk that can be folded into the IRP analytical framework.

g. Transmission

On pages 59 and 61 of the 2017 IRP, Pacific Power requests that the Commission acknowledge its planned investment in two transmission capacity projects: Wallula to McNary, and Aeolus to Bridger/Anticline. The Commission recognizes that other states in which the Company operates require a Certificate of Public Convenience and Necessity for transmission resources. Washington has no such requirement, nor does the Commission regulate the siting of intrastate transmission lines. This function is performed by the Washington State Energy Facility Site Evaluation Council.[17]

We therefore do not to respond at this time to the Company's request for acknowledgment of its plan to build these projects. We will evaluate the prudency of these and any similar projects based on the need to serve core customers within the context of a general rate case when the Company seeks recovery of its investments. We note that the Aeolus to Bridger/Anticline project is on the eastern side of the Jim Bridger generating facility, so we presume that the line will not be used and useful to the WCA when it is completed.

h. Portfolio Scenario Cost Comparison

Pacific Power summarizes its key assumptions and portfolio results for each portfolio in Appendix M of its IRP.[18] The Quick Reference Guides are useful for giving the Commission,

[17] *See* RCW 80.50.060, RCW 80.50.020.
[18] 2017 IRP, Vol. 2, p. 263.

stakeholders, and policymakers a quick comparative overview of the costs and risks of each portfolio in the Company's IRP. We ask that in future IRPs, Pacific Power more prominently display these tables in its IRP.

i. Emissions Price Modeling and Cost Abatement Supply Curve

State statute and Commission rule require an electric utility's preferred portfolio to represent the lowest reasonable cost, which includes "public policies regarding resource preference adopted by Washington state or the federal government, and the cost of risks associated with environmental effects including emissions of carbon dioxide."[19] That is, the Company must consider both known regulatory costs and the risk of future costs.

Since the 2015 IRP, there have been significant changes to greenhouse gas emissions regulations, including increases to the renewable portfolio standards in California and Oregon, possible repeal and replacement of the Clean Power Plan (CPP), the implementation of Washington's Clean Air Rule, and more recently, ambiguity with the rule's legality. Despite the uncertainty surrounding the Clean Air Rule and the CPP, there continues to be considerable legislative and regulatory risk associated with greenhouse gas emissions. In the last two years at the Washington State legislature, more than a dozen bills were introduced that would impose a cost on greenhouse gas emissions, or place limits on emissions.[20] Voters rejected a carbon tax at the ballot in 2016,[21] but another initiative has been filed, which may appear on the ballot in November 2018.[22] Additionally, Washington State and the federal government are being sued to require regulation of the impacts of fossil fuels.[23]

These uncertainties in carbon policy exemplify the shifting regulatory terrain challenging the Company's planning efforts. In this environment, it is imperative that utility planners recognize the risks and uncertainties associated with greenhouse gas emissions and identify a reasonable, cost-effective approach to addressing them.

Pacific Power handled this by modeling two iterations of a hypothetical CPP as a proxy for potential future carbon regulation. In the 2015 IRP acknowledgment letter, the Commission asked that the Company model a sensitivity for both a carbon trading system and carbon tax system in its 2017 IRP, and consult with Commission Staff regarding the appropriate assumptions and inputs. While we are disappointed to see that these analyses were not done, the Company instead highlighted its CPP

[19] RCW 19.280.020(11); WAC 480-100-238(2)(b).
[20] *See,* e.g. HB 1144, HB 1155, HB 1646, HB 2230, HB 2839, SHB 2995, SB 5127, SB 5385, SB 5509, SB 5930, SB 6096, SB 6203, SB 6335, and SB 6629.
[21] Washington Carbon Emission Tax and Sales Tax Reduction, Initiative 732.
[22] Seattle Times, "New Washington initiative would put fee on carbon emissions", March 2, 2018. https://www.seattletimes.com/seattle-news/environment/new-washington-initiative-would-put-fee-on-carbon-emissions/
[23] Associated Press, "Activists Sue Washington State for Tougher Climate Policy", February 16, 2018. https://www.usnews.com/news/best-states/washington/articles/2018-02-16/activists-sue-washington-state-for-tougher-climate-policym, and Bloomberg, "Teenagers Defeat Trump's Move to Kill Climate Change Lawsuit", March 7, 2018. https://www.bloomberg.com/news/articles/2018-03-07/youths-defeat-trump-s-move-to-kill-climate-change-lawsuit.

modeling study and an alternative CO2 price sensitivity.[24] We understand Pacific Power's contention that a trading system has essentially the same impact as a tax system on the Company's costs; however we do not find that the Company's analyses incorporated the cost of risk of future greenhouse gas regulation.

As we note at the beginning of this document, RCW 19.280.030(f) requires utilities to prepare a long term plan that identifies the near term and future needs at the lowest reasonable cost and risk to the utility and its ratepayers. To determine lowest reasonable cost, the utility must consider "the risks imposed on the utility and its ratepayers, public policies regarding resource preference adopted by Washington state or the federal government, and the cost of risks associated with environmental effects including emissions of carbon dioxide."[25] By modeling only existing state and provincial regulation in its preferred portfolio, the Company's price of carbon does not consider the complete risk of additional regulation and, as such, risks not meeting statutory requirements. In future IRPs, Pacific Power should incorporate the cost of risk of future greenhouse gas regulation in addition to known regulations in its preferred portfolio. This cost estimate should come from a comprehensive, peer-reviewed estimate of the monetary cost of climate change damages, produced by a reputable organization. We suggest using the Interagency Working Group on Social Cost of Greenhouse Gases estimate with a three percent discount rate. Pacific Power should also continue to model other higher and lower cost estimates to understand how the resource portfolio changes based on these costs.[26]

The Company should also develop a supply curve of emissions abatement. We envision this as a tool that considers all mechanisms for reducing emissions including energy efficiency, emissions controls, plant conversions, and their costs. We asked the Company to develop a carbon abatement cost curve for inclusion in the 2017 IRP, but the Company did not to do so. We again ask the Company to include this cost curve in its 2019 IRP. This analysis should identify all programs and technologies reasonably available in Pacific Power's service area, then use the best available information to estimate the amount of emissions reductions each option might achieve, and at what cost. This tool would increase transparency on the issue, and would allow the Company, the Commission, and stakeholders to engage in meaningful and informed conversations regarding the costs and benefits of reducing Pacific Power's emissions. It would also guide policymakers in their efforts to reduce emissions in a least-cost manner. We encourage the Company to work with Staff and other stakeholders who can provide further detail and assist in scoping this request.

IV. Conclusion

The Commission acknowledges that Pacific Power's 2017 Integrated Resource Plan complies with RCW 19.280.030 and WAC 480-100-238, on the condition that the recommendations made concerning the 2017 IRP are addressed in its submission of the 2019 Integrated Resource Plan. The Commission expects Pacific Power to follow the recommendations outlined in this letter as it develops future IRPs.

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[24] Pacific Power 2017 IRP, Vol. 2, p. 36.
[25] RCW 19.280.020(11).
[26] For example, for complying with Executive Order 14-04, the Washington State Energy Office recommends state agencies use the Interagency Working Group on Social Cost of Greenhouse Gases estimate with a two and one-half percent discount rate.

V. Separate Statement of Commissioner Balasbas on Part III i.

I agree with my colleagues that in future IRPs, Pacific Power should incorporate the cost of risk of future greenhouse gas regulation in addition to known regulations in its preferred portfolio. However, for the reasons outlined below, I respectfully disagree with my colleague's expectation that Pacific Power use in its preferred portfolio the social cost of carbon as the proxy for future greenhouse gas regulation.

The 2018 legislature considered, but did not take final action on, House Bill No. 2839 and Senate Bill No. 6424. These bills, among other provisions, amended Commission statutes to require use of a "greenhouse gas planning adder" when evaluating integrated resource plans as well as intermediate-term and long-term resource options selected by electrical and gas companies under Commission jurisdiction.[27] The greenhouse gas planning adder can also be referred to as the social cost of carbon. The legislature's mere consideration of this provision indicates there is not clear authorization in current statute for the Commission to require use of the social cost of carbon in IRPs.

The expectation for Pacific Power to use the social cost of carbon in its preferred portfolio is a clear statement that the 2018 legislation was irrelevant. I strongly disagree and would instead defer to the legislature's judgment of the Commission's statutory authority.

When commenting on IRPs, it is appropriate for the Commission to request scenarios using specific assumptions. However, I do not believe the Commission should mandate use of specific assumptions in the ***utility's*** preferred portfolio. My preference would have been to ask Pacific Power to model a separate scenario in its 2019 IRP that uses the social cost of carbon. Then Pacific Power can decide whether that model outcome should be used in its preferred portfolio (i.e. the lowest reasonable cost portfolio).

Finally, I disagree with my colleagues mandating the use of the social cost of carbon to represent the "lowest reasonable cost" portfolio. As the Federal Energy Regulatory Commission recently stated in an order, "Without complete information, an analysis using the Social Cost of Carbon calculations would necessarily be based on multiple assumptions, producing misleading results."[28] While IRPs are by necessity assumption driven, I am concerned that requiring use of a speculative tool to choose a preferred portfolio could lead to higher than necessary rates for utility customers.

[27] ESHB 2839, Section 3.
[28] FERC Docket Nos. CP14-554-002, CP15-16-003, CP15-17-002 Order on Remand Reinstating Certificate and Abandonment Authorization, ¶ 41 (Issued March 14, 2018).