Witness OCS – 2 Second Rebuttal

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of	**)**	**Docket No. 17-035-40**
Rocky Mountain Power for Approval of	**)**	
a Significant Energy Resource Decision	**)**	
and Voluntary Request for Approval of	**)**	
Resource Decision	**)**	

CONFIDENTIAL SECOND REBUTTAL TESTIMONY OF

PHILIP HAYET

FOR THE

OFFICE OF CONSUMER SERVICES

April 17, 2018

REDACTED

Subject to Rule 746-1-602 and 603

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, TITLE AND COMPANY.

A. My name is Philip Hayet. My business address is 570 Colonial Park Drive, Suite 305, Roswell, Georgia, 30075. I am Vice President of J. Kennedy and Associates, Inc. ("Kennedy and Associates").

Q. HAVE YOU ALREADY SUBMITTED TESTIMONY IN THIS DOCKET?

A. Yes. I submitted direct testimony on December 5, 2017 and rebuttal testimony on January 16, 2018, both on behalf of the Utah Office of Consumer Services ("Office").

Q. WHAT IS THE PURPOSE OF THIS REBUTTAL TESTIMONY?

A. In response to the Office and the Division of Public Utility's ("Division") January 19, 2018 Motion to Vacate the remaining schedule in this proceeding due to PacifiCorp's acknowledged incomplete supplemental direct testimony, the Commission ordered the Company to file additional materials to complete its application.[1] The Company filed its second supplemental direct testimony on February 16, 2018, and then followed up with a corrected filing on February 23, 2018. I have reviewed the Company's corrected economic analyses and present the results of my evaluation in this testimony. I respond to both the Company's first and second supplemental direct testimonies, specifically to testimony filed by Company witnesses Ms. Cindy Crane, Mr. Rick Link, Mr. Chad Teply, and Mr. Rick Vail. Finally, I present my conclusions and recommendations regarding the Company's decision to acquire new wind resources, and to construct new and upgrade existing transmission facilities (collectively referred to as the "Combined Projects").

[1] The Commission's order issued February 13, 2018, was entitled, Order Granting Motion to Vacate Remaining Schedule and Amended Scheduling Order.

Q. WHAT ARE YOUR OVERALL OBSERVATIONS ABOUT THIS CASE?

A. In its latest filing, the Company proposes to acquire new wind resources ("Wind Projects") and to construct the Aeolus-to-Bridger/Anticline transmission line and network upgrades ("Transmission Projects") in southeastern Wyoming, supported by results from its request for proposals ("RFP") for wind resources ("2017R RFP"), its RFP for solar resources ("2017S RFP"), and its interconnection re-study process and new system impact studies ("SIS"). The projects that were originally described by the Company as economic projects based on "a time-limited opportunity"[2] to take advantage of production tax credits ("PTC") are now being referred to as "necessary to meet an identified resource need."[3] While it is true that the economics of these projects are time-limited due to the availability of PTCs, PacifiCorp's request to invest over $2 billion on these projects and another $1 billion on repowering projects as proposed in Docket No. 17-035-39 represents a significant commitment of ratepayer funds that is unnecessary and full of risks. It would be inaccurate for PacifiCorp to suggest that the only reason it is promoting these projects is because of the value that they provide to ratepayers. There should be no doubt that PacifiCorp is promoting these projects wholeheartedly because they will help to build the Company's rate base and increase its earnings.

Q. WHAT ARE YOUR FINDINGS AND CONCLUSIONS?

A. I have reviewed the Company's economic analyses and have identified issues that I discuss in this testimony. One of the Company's studies, which I refer to as the "to-2036" analysis, includes a recent modification to the PTC modeling methodology, which biases the results

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[2] PacifiCorp's June 30, 2017 Application in this proceeding, at page 2.
[3] Cindy Crane Supplemental Direct Testimony, January 16, 2018, at lines 24-26.

in favor of selecting self-build (Benchmark Resources) and build transfer agreement ("BTA") options, as opposed to power purchase agreement ("PPA") options. The Company's longer-term analysis, the "to-2050" analysis, also has issues that relate to the fact that the Company did not run its normal production cost and optimal expansion planning modeling tools, the Planning and Risk ("PaR") and the System Optimizer ("SO") models, during the 2037 to 2050 time-period. However, this flaw is less pronounced in the analysis of the Combined Projects than it is in the analyses conducted in the repowering proceeding.

In addition to the modeling flaws, I also discuss potential legitimate risks that could result in ratepayers being worse off if these projects go forward. These risks include cost overruns, less energy production than anticipated, and delays in project completion, resulting in the loss of some or all of the PTC benefits. Furthermore, the Company ignored sensitivity case results that indicate that acquiring solar resources could result in a lower cost resource portfolio.

Given the potential bias in the Company's analyses, the potential for risks that the Company did not address, the magnitude of the investments (more than $2 billion), the likelihood that there may be lower cost resource alternatives available, and the fact that the Company does not have a capacity need driving the decision to acquire the new projects, I conclude that the Company has not met the requirements of Utah Code § 54-17-402 and has not shown that these projects will most likely result in the acquisition, production, and delivery of electricity at the lowest reasonable cost and least risk possible, while addressing reliability and other factors.

Q. WHAT ARE YOUR RECOMMENDATIONS?

A. I recommend that the Commission deny the Company's request. I could possibly be convinced to view these projects in a different light if these projects were necessary to meet a reliability requirement, however, I do not believe the Company has demonstrated a reliability need in this proceeding. These Projects are primarily justified on economics, and the benefits that PacifiCorp has identified are neither substantial nor assured, and simply do not outweigh the risks for ratepayers. However, if the Commission ultimately is persuaded to approve PacifiCorp's request regarding the Combined Projects, I recommend that it impose the set of conditions that I discuss below.

II. BACKGROUND

Q. PLEASE SUMMARIZE THE MOST RECENT STATUS OF THE COMBINED PROJECTS IN THIS PROCEEDING?

A. Since the Commission issued its order on September 22, 2017 approving PacifiCorp's request for proposal ("RFP") process for wind resources (Docket No. 17-035-23), PacifiCorp has worked to complete its Wind RFP (2017R RFP), and its Solar RFP (2017S RFP). In its 2017R Order, the Commission recommended, but did not require, that PacifiCorp modify its 2017R RFP to allow bidders to submit solar options in addition to wind options. The Commission's reason was explained in the following two statements from page 8 of its 2017R Order:

> We find inconclusive the evidence related to current utility scale solar prices compared against the solar prices PacifiCorp used in its analysis.
>
> We find the evidence from some parties with respect to lower solar prices, though, sufficiently persuasive to justify our suggested modification that the RFP be expanded to include solar resources that are able to interconnect at any point in the PacifiCorp system.

Out of a concern about its ability to maintain the 2017R RFP schedule, PacifiCorp decided instead to conduct a separate Solar RFP.

A. COMPANY INITIAL DIRECT FILING (JUNE 30, 2017)

Q. WHAT DID PACIFICORP'S ANALYSES ASSUME THAT THE COMBINED PROJECTS WOULD CONSIST OF WHEN IT MADE ITS INITIAL FILING?

A. In its initial filing, PacifiCorp's analyses assumed that the Company would acquire four proxy resources, totaling 860 MW, at a cost of $1.37 billion. One was a 110 MW self-build project, McFadden Ridge II, and the other three were considered Benchmark Resources that were under the control of a third-party developer. The three projects were TB Flats I, TB Flats II, and Ekola Flats, and the projects were 250 MW each. In addition, PacifiCorp assumed that with the completion of the Transmission Projects, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** MW qualifying facility ("QF") wind projects would also be constructed by 2020, known as **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].** In total, the Company assumed that 1,180 MWs of new wind resources would be added to its System in southeastern Wyoming. PacifiCorp also assumed that it would cost **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** million to construct the Aeolus-to-Bridger/Anticline transmission line, and an additional **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** million to construct a set of 230 kV Network Upgrades.

Q. WHAT MODELS, ASSUMPTIONS, AND METHODOLOGIES DID PACIFICORP RELY ON WHEN IT FILED ITS INITIAL TESTIMONY?

A. PacifiCorp relied on the same models, the System Optimizer ("SO") and the Planning and Risk ("PaR") models, and much of the same modeling assumptions that were used to perform the integrated resource plan ("IRP"). However, PacifiCorp updated some assumptions including its price-policy forecasts (natural gas prices, CO_2 costs, and market price forecasts), up-front wind and transmission capital costs, run-rate operating costs, and energy output associated with the wind resources.[4] For all generic resource options other than wind, such as solar, PacifiCorp used the same assumptions as it had used in the IRP. PacifiCorp also used the same modeling methodologies including the use of a levelized cost representation to model both capital revenue requirements and Production Tax Credits ("PTC") in the SO optimization analysis. The significance of this will be discussed further below.

Q. WHAT DID YOU CONCLUDE IN YOUR DECEMBER 5, 2017 DIRECT TESTIMONY?

A. I concluded that the Combined Projects should be primarily viewed as an economic opportunity to take advantage of PTCs, and that the projects were faced with significant risks including the possibility of tax law changes, schedule delays, energy benefit and PTC risks, capital cost overruns, construction risks, and consequently, I concluded that the potential benefits to construct the projects did not outweigh the significant risks. Based on these concerns, I ultimately recommended that the Combined Projects should be rejected. I also recommended that if the Commission were to conclude that the Combined Projects should be approved, that certain conditions should be imposed to protect ratepayers' interests, particularly since the projects are primarily economic resource additions.

[4] OCS 1.27.

B. <u>COMPANY FIRST SUPPLEMENTAL TESTIMONY (JANUARY 16, 2018)</u>

Q. WHAT DID THE COMPANY PRESENT IN ITS SUPPLEMENTAL DIRECT TESTIMONY?

A. The Company presented results based on analyses conducted using the 2017R RFP Final Shortlist. The 2017R RFP Final Shortlist was determined based on updated best-and-final pricing bids that the Company received as of December 21, 2017. In these best-and-final bids, bidders were afforded the opportunity to account for tax law revisions that were imminent, as the Tax Cuts and Jobs Act legislation was signed into Law on December 22, 2017, which among other things lowered the corporate federal income tax rate from 35% to 21%.

Q. WHAT MODELING ASSUMPTIONS DID PACIFICORP INCLUDE IN ITS SUPPLEMENTAL DIRECT TESTIMONY ANALYSES?

A. PacifiCorp updated its cost and performance assumptions for the shortlist wind projects, price-policy assumptions (natural gas prices, CO_2 costs, and market price forecasts), load forecast assumptions, and tax-related assumptions.[5] For everything other than the Combined Projects, including all generic options, PacifiCorp relied on the same data assumptions as it had used to perform the IRP. PacifiCorp also included solar sensitivity analyses based on bids it received in the 2017S RFP. In its 2017S RFP, PacifiCorp sought new solar resources from anywhere within its System to be added by the end of 2020, limited to a maximum project size of 300 MW.

Q. DID PACIFICORP CONTINUE TO USE THE SAME MODELS AND MODELING METHODOLOGIES AS IT HAD USED IN THE IRP?

[5] Rick Link Supplemental Direct and Rebuttal Testimony, January 16, 2018, at lines 387 – 391.

A. PacifiCorp continued to use the same SO and PaR models as it had in the IRP, but PacifiCorp altered its approach to modeling PTCs. Instead of modeling PTCs using a levelized cost representation, PacifiCorp represented PTCs using non-levelized costs, which effectively biased the results in favor of selecting Company owned wind projects. Since this modeling change was introduced around the time the Tax Cuts and Jobs Act legislation was signed into Law on December 22, 2017, it is arguable that PacifiCorp changed its PTC modeling approach to counter the loss in benefits wind resources suffered due to the change in tax law.

Q. DID PACIFICORP MAKE ANY OTHER MODELING CHANGES IN ITS SUPPLEMENTAL FILING?

A. Yes, PacifiCorp made another change by including a terminal value benefit with self-build and BTA wind resources. PacifiCorp witness Link explained that the terminal value benefit was introduced to account for the additional benefit due to the remaining life of the transmission assets that may occur as far out in time as the 2051 to 2082 time period.[6] PacifiCorp asserted that this benefit will materialize if PacifiCorp redevelops the Company owned wind sites at the end of their useful lives, and builds new generation at the same sites to take advantage of the transmission facilities that would still have remaining useful life after the existing wind resources retire. Not only is this highly speculative, it is unrealistic to count on the use of the same transmission facilities without considering the need for transmission upgrades to accommodate whatever new generation would be built at the site especially considering how far out in time such potential future development would be. Even if there was a legitimate terminal value benefit that should be accounted

[6] Id. at lines 396 – 415.

for in this economic analysis, other than perhaps a net salvage value, the probability of being able to accurately calculate that value in 2050 would be extremely low. Furthermore, the concept of using a terminal value benefit is a deviation from the initial filing in this proceeding as well as the IRP, and the result of including such a terminal value benefit could further bias the project selection process because it impacts Benchmark Resources and BTA options differently than PPA options. This assumption should be removed from PacifiCorp's analysis.

Q. WHAT WERE THE SHORTLISTED PROJECTS THAT THE COMPANY EVALUATED IN ITS SUPPLEMENTAL DIRECT TESTIMONY ANALYSES?

A. PacifiCorp assumed that up to 1,270 MW of new resources could be added in southeastern Wyoming, and it further assumed it would have to reserve 240 MW for a QF transmission customer that already had an executed interconnection agreement. Thus, PacifiCorp restricted portfolios in southeastern Wyoming to 1,030 MW (1,270 – 240).[7] PacifiCorp allowed additional bids to be included in portfolios from locations outside of the constrained area.

PacifiCorp's final shortlist portfolio included four wind resources totaling approximately 1,170 MW resulting in a cost of about $1.3 billion. The projects included were McFadden Ridge II – a 109 MW Benchmark Resource, TB Flats I and II - combined into a single 500 MW Benchmark Resource, Cedar Springs – a 200 MW third party BTA resource and a 200 MW PPA resource, and Uinta – a 161 MW third party BTA resource. The capital cost assumptions were substantially lower in this filing compared to the Company's June 30, 2017 filing.

[7] Id. at lines 169 – 176.

Q. WERE THERE ANY CHANGES TO THE TRANSMISSION PROJECTS THAT THE COMPANY EVALUATED IN ITS SUPPLEMENTAL DIRECT TESTIMONY ANALYSES?

A. The Company's estimate to construct the Aeolus-to-Bridger/Anticline transmission line remained unchanged at an estimated cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** million, however, its cost to construct the 230 kV Network Upgrades increased by approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** million to an estimated cost of about **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** million.[8]

C. COMPANY SECOND SUPPLEMENTAL (FEBRUARY 16, 2018)

Q. WHAT TRANSPIRED AFTER THE COMPANY MADE ITS FIRST SUPPLEMENTAL FILING?

A. After the Company filed its supplemental direct testimony, the Division and the Office filed a motion to vacate the remaining schedule and set a new schedule to allow parties more time to evaluate the extensive filing PacifiCorp had made. Though PacifiCorp disagreed with the Division and Office, it also acknowledged that it still needed additional time to complete interconnection studies and it offered to extend the schedule. In its Order issued February 13, 2018, the Commission noted that PacifiCorp admitted its filing was incomplete, ordered PacifiCorp to file the missing information, and extended the remaining procedural schedule.

[8] Rick Vail Supplemental Direct and Rebuttal Testimony, January 16, 2018, at lines 84-89.

Q. WHAT MODELING ASSUMPTIONS DID PACIFICORP CHANGE IN ITS ANALYSES SUPPORTING ITS SECOND SUPPLEMENTAL DIRECT TESTIMONY FILING THAT IT MADE ON FEBRUARY 16, 2018?

A. PacifiCorp completed its interconnection restudy process and new system impact studies ("SISs") and determined that different wind resources would need to be included in its 2017R final shortlist. PacifiCorp also determined that it could increase the transfer capability across the constrained area from 1,270 MW to 1,510 MW, and hence include additional wind resources in southeastern Wyoming.

Q. WHY DID PACIFICORP CHANGE ITS SHORTLIST AS A RESULT OF COMPLETING ITS INTERCONNECTION STUDIES?

A. As the Company finalized its transmission interconnection studies based on the assumption that the D2 segment would be constructed, it determined there was a specific point in the interconnection queue, at project Queue ID Q0713, at which projects with lower priority in the queue could not be interconnected until the full set of Gateway West and South transmission upgrades were added. The Company's McFadden Ridge II Benchmark Resource had to be removed from the shortlist because it was one of the projects that had a lower priority in the interconnection queue. This apparently caused some amount of concern on the part of both the Utah and Oregon Independent Evaluators ("IEs"), who were responsible for monitoring the Company's competitive solicitation process in the two states.[9] The Utah IE revealed this in its February 2018 Utah Final RFP Report, in which it stated:[10]

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[9] Merrimack Energy Group, Inc. ("Merrimack") is the IE in Utah, and Bates White Economic Consulting ("Bates White") is the IE in Oregon.

[10] Merrimack Final RFP Report, February 2018, Redacted Version, page 64, at https://pscdocs.utah.gov/electric/17docs/1703523/300621IERedacFinRep2-27-2018.pdf.

> The IEs, on the other hand, expressed some frustration that the bid selection process ended up being limited to selection of only those projects with favorable queue positions, which included the [redacted] All other proposals submitted were behind the interconnection queue constraint and would have no chance of being selected.

Q. WHAT LED PACIFICORP TO CONCLUDE THAT IT WOULD BE ABLE TO INTERCONNECT UP TO 1,510 MW IN SOUTHEASTERN WYOMING?

A. As PacifiCorp completed its interconnection re-study process and new system impact studies it determined it could increase the transfer capability across the constrained area from 1,270 MW to 1,510 MW, which led it to determine that it could replace the 109 MW McFadden Ridge II project with a larger project as long as the new project could meet the requirement of having an interconnection queue position of Q0713 or better. With the increase in the transfer capability, PacifiCorp found that the Ekola Flats Benchmark Resource (250 MW) could be added, as it was able to meet the interconnection queue position requirement.

Q. WHAT OTHER ASSUMPTIONS CHANGED IN THE COMPANY'S SECOND SUPPLEMENTAL DIRECT TESTIMONY ANALYSES?

A. The SO and PaR models remained the same, and the assumption regarding using non-levelized PTCs remained the same. The primary change the Company made was to include the Ekola Flats projects, including adjusting the 230 kV transmission upgrade assumptions. In addition, the Company made other changes to correct modeling errors that were discovered to properly include sales tax for some of the wind resources.[11]

Q. WHAT IS THE COST OF THE FINAL SET OF SHORTLISTED PROJECTS?

[11] Rick Link Second Supplemental Direct Testimony, February 16, 2018, beginning at line 189.

A. PacifiCorp's final shortlist portfolio includes four wind resources totaling approximately 1,311 MW at a cost of $1.46 billion. The projects include Ekola Flats – a 250 MW Benchmark Resource, TB Flats I and II - combined into a single 500 MW Benchmark Resource, Cedar Springs – a 200 MW third party BTA resource and a 200 MW PPA resource, and Uinta – a 161 MW third party BTA resource.

Q. WERE THERE ANY CHANGES TO THE TRANSMISSION PROJECTS THAT THE COMPANY EVALUATED IN ITS SECOND SUPPLEMENTAL DIRECT TESTIMONY ANALYSES?

A. The Company's estimate to construct the Aeolus-to-Bridger/Anticline transmission line remained unchanged at an estimated cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** million, however, its cost to construct the 230 kV Network Upgrades increased again, by approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** million to an estimated cost of about **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** million.[12]

Q. PLEASE COMPARE THE DIFFERENT RESOURCES THAT WERE EVALUATED IN THE ANALYSES THE COMPANY CONDUCTED FOR ITS DIRECT, FIRST SUPPLEMENTAL AND SECOND SUPPLEMENTAL TESTIMONIES.

A. Table 1 below compares the different resources identified.

[12] Rick Vail Second Supplemental Direct Testimony, February 16, 2018, lines 99 to 108.

Table 1
Projects Proposed (MW)

	Direct	1st Supplemental	2nd Supplemental
	6/30/2017	1/16/2018	2/16/2018
McFadden II	110	109	
Ekola Flats	250		250
TB Flats I	250	250	250
TB Flats II	250	250	250
Cedar Springs		400	400
Uinta		161	161
Total Request	**860**	**1,170**	**1,311**

III. PROBLEMS WITH PACIFICORP'S ECONOMIC EVALUATION

Q. WHAT ARE YOUR CONCERNS WITH PACIFICORP'S ECONOMIC ANALYSIS?

A. I primarily have two areas of concern. First, I believe the Company made changes to its modeling methodology that essentially ensured nearly all of its analyses would result in positive economic benefits. Second, I do not believe the Company has adequately considered all legitimate risks that could ultimately harm ratepayers if it were to proceed with the Combined Projects.

A. MODELING METHODOLOGY

Q. HOW DID THE MODELING METHODOLOGY CHANGES AFFECT PACIFICORP'S RESULTS?

A. As discussed above, beginning with the first supplemental direct testimony analysis, the Company introduced two modeling methodology revisions, one was a change from modeling PTC benefits using a levelized to a non-levelized representation, and the other was to include terminal value benefits for the first time. These two modeling methodology changes resulted in an incremental increase of nearly $262 million dollars of additional benefits being added to PacifiCorp's 20-year ("to-2036 study") net present value economic evaluation results.[13] Without these changes, the Combined Projects would have been uneconomic in some of the cases in the to-2036 study. The PTC modeling change only affected the to-2036 study results, not the to-2050 study results, and added $233 million in net present value benefits to the to-2036 study. The change to include terminal value benefits increased both the Company's to-2036 study and the Company's to-2050 study, because the terminal value is levelized through the 2036 study period. The new terminal value assumption resulted in an additional $29 million being added to the benefit in the to-2036 study, and an additional $42 million being added to the benefit in the to-2050 study, on a net present value basis.

Q. HAS PACIFICORP EVER JUSTIFIED ITS PRIOR PTC MODELING METHODOLOGY OF USING A LEVELIZED COST REPRESENTATION?

A. Yes, the Company also made the same modeling methodology change midstream in the repowering proceeding (Docket No. 17-035-39), when it made a supplemental filing on February 1, 2018 to account for the impact of tax law reforms. Prior to that, in a discovery response, the Company essentially asserted that the use of a levelized cost representation was more appropriate. The Company stated in that response:[14]

> Income taxes are a component of revenue requirement, which spreads the initial up-front cost of assets over the life of those assets, accounting for return on investment, return of investment, and taxes. Production tax credits (PTC) represent a credit that offset income taxes, and therefore, a reduction to revenue requirement. Considering that PTCs are a component of income taxes that are included in revenue requirement, they are levelized over the life of the project

[13] OCS estimate.
[14] The Company's response to OCS 5.8 from docket 17-035-39 is included as OCS Exhibit 2.1 Second Rebuttal.

> in the same way that other components of revenue requirement are levelized (i.e., return on and return of investment).

Essentially, PacifiCorp's position at the time was that PTCs should be represented the same way that capital cost revenue requirements are represented because both have income tax components that are included in project revenue requirements.

Q. HOW HAS PACIFICORP EXPLAINED ITS RECENT CHANGE TO MODEL PTC BENEFITS USING A NON-LEVELIZED REPRESENTATION?

A. At line 38 of his January 16, 2018 supplemental direct testimony in this proceeding, Mr. Link explained the Company's new approach as follows:

> The treatment of production tax credits ("PTCs") in the system modeling scenarios extending out through 2036 has been changed to better reflect how the PTCs will flow through to customers, which makes the treatment consistent with the nominal revenue requirement results that extend out through 2050.

Based on the Company's new approach in which PTCs are modeled as non-levelized values and capital revenue requirements continue to be modeled as levelized values, the entirety of the PTC benefits will be captured in the to-2036 economic evaluation, while a significant portion of the capital related revenue requirements will be excluded from that analysis. The problem with PacifiCorp's new modeling approach is that it essentially maximizes wind PTC benefits and minimizes capital costs that are included in the to-2036 economic evaluation, which ultimately leads to a bias that favors selection of certain resources.

Q. EXPLAIN HOW CAPITAL COSTS ARE ESSENTIALLY MINIMIZED IN THE TO-2036 ANALYSIS.

A. Capital revenue requirements are included in rates based on declining revenue requirement profiles (front-end loaded), but in economic analyses capital revenue requirements are typically represented using a real levelized revenue requirement profile (back-end loaded).[15] Because studies are performed based on present value analyses, it would make no difference how capital costs were represented if the entire operating life of the resource existed within the length of the study period. However, when the operating life of a resource exceeds the study period, such as in the Company's to-2036 analysis, then some of the capital revenue requirements have to be excluded from the study. Because real levelized cost profiles are back-end loaded, a substantial portion of the actual capital costs are excluded for studies that end in 2036. By modeling capital revenue requirements using a real levelized cost representation, those costs are essentially minimized in the to-2036 economic analysis.

Q. COULD YOU GIVE AN EXAMPLE DEMONSTRATING THAT THE WAY CAPITAL REVENUE REQUIREMENTS AND PTCS ARE REPRESENTED LEADS TO DIFFERENT COSTS BEING EXCLUDED IN THE ECONOMIC ANALYSIS?

A. Yes, Figure 1 below compares cumulative net present value revenue requirements (capital cost revenue requirements less PTCs) for the Final Shortlist wind project, Uinta, using the Company's original methodology that it used in direct testimony, "Levelized Capital, Levelized PTC", and its new methodology, "Levelized Capital, Non-Levelized PTC". In addition, the figure also includes a third approach to modeling the benefits and costs, "Non-Levelized Capital, Non-Levelized PTC". This method will be discussed further below.

[15] In general, I follow PacifiCorp's convention of referring to a real levelized profile as just a levelized profile.

Figure 1
Comparison of Net Project Costs
Cumulative Present Value Cost Streams

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Because the results are presented as cumulative present value dollars, each of the cost streams converge when the end of the operating life is reached.[16] These results, which have been determined prior to considering energy benefits, indicate that by 2050 the wind capital revenue requirement will exceed the PTC benefit, for a cumulative net cost of about **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** million. The graph also indicates that regardless of how capital costs and PTCs are represented, there would essentially be no difference in the results in the analysis, if the study period is long enough to capture the full set of capital revenue requirement costs and PTC benefits. However, if

[16] 230 kV network upgrades and the D2 segment will have revenue requirements extending further out to 2082, as they have 62-year operating lives. This mean that even in the to-2050 analysis some of the transmission related capital revenue requirements will be excluded from the to-2050 analysis.

the study period ends before that, such as in 2036, then some of the costs and benefits may be excluded from the study period, depending on the representation of the costs and benefits. The vertical line serves to highlight the results at 2036.

The solid line reflects the results based on the methodology that the Company relied on in its direct testimony, in which capital cost revenue requirements and PTCs were both levelized. The dashed line is from the Company's latest analysis in which capital cost revenue requirements are still levelized, but PTCs are represented as non-levelized values, and finally, the line with the diamond markers is the third option I mentioned, in which capital revenue requirements and PTCs are both represented as non-levelized values.

Q. WHAT ARE THE ADVANTAGES OF MODELING BOTH PTCS AND CAPITAL COST REVENUE REQUIREMENTS USING NON-LEVELIZED REPRESENTATIONS?

A. By changing from modeling levelized to non-levelized PTCs, the Company biased its results by including the most benefits, while at the same time including the least capital revenue requirements possible. The Company asserts that the change was appropriate because it is now more aligned with how PTCs will be reflected in rates, yet its treatment of capital revenue requirements is not aligned with how those costs will flow through rates. The additional line in Figure 1 (blue diamond markers) represents both capital revenue requirements and PTCs using non-levelized costs, and has the advantage of modeling both streams consistently, and it better reflects how the capital revenue requirements and PTCs benefits flow through rates.

Q. WHAT ARE THE IMPACTS OF PACIFICORP'S CHANGE IN THE PTC MODELING METHODOLOGY, AND THE IMPACTS OF THE MODELING APPROACH YOU HAVE IDENTIFIED?

A. Table 2 compares the Company's results using its current PTC modeling approach (Link Table 2-SS corrected column) to its previous PTC modeling approach (Previous Approach column). The table also includes the alternative modeling approach that I have introduced.

Table 2
Comparison of Capital and PTC Levelization Methodologies
PaR Stochastic Mean PVRR(d)
(Benefit)/Cost of New Wind

Price-Policy Scenario PaR to-2036	**Link Table 2-SS Corrected** Levelized Capital Non-Levelized PTC	**Previous Approach** Levelized Capital Levelized PTC	**Alternative Approach** Non-Levelized Capital Non-Levelized PTC
Low Gas, Zero CO_2	(150)	83	156
Low Gas, Medium CO_2	(179)	54	127
Low Gas, High CO_2	(337)	(104)	(30)
Medium Gas, Zero CO_2	(319)	(86)	(13)
Medium Gas, Medium CO_2	(357)	(124)	(51)
Medium Gas, High CO_2	(448)	(215)	(141)
High Gas, Zero CO_2	(569)	(336)	(262)
High Gas, Medium CO_2	(603)	(371)	(297)
High Gas, High CO_2	(695)	(462)	(388)

Under PacifiCorp's new approach (Link Table 2-SS Corrected), all price-policy cases show positive benefits that equal or exceed $150 million. The second column reflects what the results would have been had PacifiCorp continued using its previous PTC modeling methodology. The benefits using the prior PTC modeling methodology are about $233 million lower in every price-policy case. In other words, the Company has achieved substantially greater wind project benefits by doing nothing more than changing the PTC modeling representation, which is more of a slight of hand than a true increase in project benefits. Had the Company continued to use its previous approach, two of the price-policy cases (Low Gas, Zero CO_2, and Low Gas, Medium CO_2), would have been clearly uneconomic. Furthermore, three other cases, the Low Gas, High CO_2, Medium Gas, Zero CO_2, and Medium Gas, Medium CO_2 cases, demonstrate relatively small benefits, which is not a compelling enough case for proceeding given other risks of the Combined Projects.

Under the alternative modeling approach in which capital revenue requirements and PTCs are both modeled using non-levelized costs, consistent with how the costs and benefits will flow through rates, the benefits in each price-policy case decline an additional $75 million compared to the Company's previous results. This modeling method results in an additional case demonstrating relatively small benefits (Medium Gas, High CO_2), which further argues against proceeding with construction of the Combined Projects.

Q. WERE THE PRICE-POLICY ASSUMPTIONS, WHICH THESE RESULTS WERE BASED ON, UPDATED SINCE THE COMPANY MADE ITS INITIAL FILING IN JUNE 2017?

A. Yes, in its direct testimony, the Company used its April 26, 2017 Official Forward Price Curve ("OFPC") natural gas price forecasts and versions of third party forecasts that were current at that time. In its most recent testimony, the Company used its December 30, 2017 OFPC natural gas price forecasts and updated third party forecasts.[17] The latest forecasts all reflect lower natural gas prices, which is consistent with long-term trends that have been observed in the natural gas market. The Company also used more recent third-party CO_2

[17] Link Supplemental Direct and Rebuttal Testimony, January 16, 2017, lines 443 to 447.

forecasts, which resulted in a reduction in and delay of the start of CO_2 costs from what the Company previously relied on. This is also consistent with my observations of trends at other utilities regarding their CO_2 forecasts, particularly since no CO_2 legislation has passed at the national level. Furthermore, it is quite possible there will be no CO_2 requirements at all in the to-2036 study horizon, and it is certainly possible that there may be no CO_2 requirements in the to-2050 study horizon. Therefore, I continue to believe that there is a high probability that natural gas and CO_2 costs will be in the low to medium price forecast range, and I believe that substantial consideration should be given to the Low to Medium Gas/Zero CO_2 results found in Table 2 above.

Q. YOU MENTIONED THAT ANOTHER MODELING CHANGE THE COMPANY MADE WAS TO INCLUDE A TERMINAL VALUE BENEFIT IN ITS ECONOMIC EVALUATION. HOW HAVE THE RESULTS BEEN IMPACTED BY THIS BENEFIT?

A. PacifiCorp assumes that at the end of the operating life of each owned wind project, the transmission assets will provide additional value at the wind sites because they will still have an additional 32 years of useful life remaining. PacifiCorp accounted for this so-called terminal value benefit by adding a nominal benefit of approximately $400 million to the results in year 2050. The probability that the Company would be able to accurately determine a single benefit in the year 2050 is very low. This simplistic assumption increased the project benefit of each price-policy case by $42.4 million on a net present value basis. I believe this value is highly questionable and should not have been included in the analysis. Table 3 below contains Mr. Link's to-2050 results and compares them to the same results without the additional terminal value amount.

Table 3
Comparison of Cases With and Without Terminal Value
PaR Stochastic Mean PVRR(d)
(Benefit)/Cost of New Wind

Price-Policy Scenario PaR to-2050	Link Table 3-SS Corrected	Terminal Value Removed
Low Gas, Zero CO_2	184	226
Low Gas, Medium CO_2	127	170
Low Gas, High CO_2	(147)	(104)
Medium Gas, Zero CO_2	(92)	(50)
Medium Gas, Medium CO_2	(167)	(124)
Medium Gas, High CO_2	(304)	(261)
High Gas, Zero CO_2	(448)	(405)
High Gas, Medium CO_2	(499)	(457)
High Gas, High CO_2	(635)	(593)

The original results already demonstrate relatively low benefits in four out of nine of the cases (less than $150 million in benefits). After removing the terminal value benefit assumption, the benefits declined by $42 million in each of the price-policy cases, and one more case has benefits less than $150 million (Medium Gas, Medium CO_2).

B. <u>SOLAR SENSITIVITY</u>

Q. AS SHOWN ABOVE, THE COMPANY'S SHORTLIST WIND PROJECTS DO NOT APPEAR SUFFICIENTLY COMPELLING COMPARED TO THE STATUS QUO CASE. HOW DID THE COMPANY'S SHORTLIST WIND PROJECTS COMPARE TO THE SOLAR PROJECTS IDENTIFIED IN THE 2017S RFP?

A. The Company developed a sensitivity analysis based on the Medium Gas, Medium CO_2 and the Low Gas, Zero CO_2 price-policy cases to examine whether it would be beneficial to acquire solar resources either without the Combined Projects ("Solar Only"), or in combination with the Combined Projects ("Solar plus Combined Projects"). Mr. Link presents results of acquiring solar resources without the Combined Projects in Table 4-SS Updated in his second supplemental direct testimony. The Company's results, based on the Stochastic Mean PaR to-2036 analysis for the Medium Gas, Medium CO_2 case indicate that the Combined Projects case would be $129 million more economic than the Solar Only case. The Company's results for the Low Gas, Zero CO_2 scenario indicate that the Combined Projects case would be just $11 million more economic than the Solar Only case, which is a very small amount. In addition, the Company also presents results that indicate that customers would be better off with the Solar Projects by a small amount, $11 million, when the same analysis is performed using the Stochastic Mean PaR model.

Q. WHAT DOES MR. LINK CONCLUDE ABOUT THE SOLAR PROJECTS BASED ON THESE RESULTS?

A. In his testimony, Mr. Link concludes that "This sensitivity does not support an alternative resource procurement strategy to pursue solar PPA bids in lieu of the Combined Projects. This would leave the significant benefits from the Combined Projects, which include building a much-needed transmission line, on the table." (Link Corrected Second Supplemental Direct Testimony at line 445)

Q. DO YOU AGREE WITH MR. LINK?

A. No, I do not, and I do not believe the Company has been completely transparent in the results the Company chose to discuss. The Company only discussed results based on its to-2036 analysis, and as I discussed above, the Company introduced a significant modeling change by representing PTC benefits using a non-levelized representation, whereas previously, it had modeled PTC benefits using a levelized representation. As will be discussed further below, this tends to favor selection of Company owned wind projects over Solar PPA projects. The following two tables compare the Company's to-2036 Solar Sensitivity results to results based on the same case but with PTC benefits modeled using the same method the Company had used in Direct Testimony and in the IRP prior to that (levelized PTC representation). Table 4 below presents the results of Medium Gas, Medium CO_2 case.

Table 4
Solar Sensitivity Modeling Comparison (Medium Gas, Medium CO_2)

	Medium Gas, Medium CO_2 to-2036	**Solar Only (Confidential)**	**Wind Only [18]**
A	Lev Capital, Non-Lev PTC (Current Approach)	(228)	(357)
B	Lev Capital, Lev PTC (Prior Approach)	(228)	(124)
C	Non-Lev Capital, Non-Lev PTC (Alternative)	[redacted]	(51)

Beginning with the results in Row B, those reflect the PTC modeling representation the Company used in analyses for Direct testimony, in which PTC values were levelized (Prior Approach). Had PacifiCorp continued to use that approach it would have reported that the Solar Only Sensitivity case was more economic than the Wind Only case by $104 million in the Medium Gas, Medium CO_2 case (228 - 124). The results in Row A (Current Approach) reflect that by switching to a new mathematical representation of PTCs (non-levelized) in its supplemental direct testimony, the Company was able to flip the results, and determine that the benefit of Wind Only projects exceeded the benefit of Solar Only projects by $129 million (357 – 228). The change in modeling methodology had no impact on the Solar results because all of the Solar bids were submitted to the Company based on

[18] OCS Estimates, See Table 2.

PPA agreements, and the bids had no PTC component that could be adjusted. The results in Row C are based on the Alternative modeling methodology that I presented above that has the advantage of representing all costs and PTCs consistently using a non-levelized representation, and best reflects how the benefits and costs will flow through rates.

I disagree with the Company and conclude that by using a consistent modeling approach that best reflects how both capital revenue requirements and PTCs will flow through rates, the Alternative Approach indicates that the Solar Only resources are more economic than the Wind Only resources in this sensitivity case. The following are the results of the Low Gas, Zero CO_2 case, and my conclusions about these results are the same as for the Medium Gas, Zero CO_2 case.

Table 5
Solar Sensitivity Modeling Comparison (Low Gas, Zero CO_2)

	Low Gas, Zero CO_2 to-2036	**Solar Only (Confidential)**	**Wind Only**
A	Lev Capital, Non-Lev PTC (Current Approach)	(139)	(150)
B	Lev Capital, Lev PTC (Prior Approach)	(139)	83
C	Non-Lev Capital, Non-Lev PTC (Alternative)	[redacted]	156

Q. ABOVE, YOU MENTIONED THAT THE COMPANY DID NOT DISCUSS ALL OF THE RESULTS IT DEVELOPED. PLEASE EXPLAIN THAT FURTHER.

A. With regard to the Solar sensitivity, Mr. Link explained the to-2036 results, but did not discuss the to-2050 results the Company also created. It is obvious that the Company performed studies using both its to-2036 and its to-2050 approaches because the results of both studies were included in the workpapers the Company provided. Had Mr. Link included the to-2050 results in testimony, he most likely would have reached a different conclusion than what he discussed based on the the Company's to-2036 results. The following figure contains a graph of annual cumulative net present value benefit results from the to-2050 study comparing the Solar Sensitivity case to the case with the Wind Only projects based on the Medium Gas, Medium CO_2 price-policy assumptions.

Figure 2
Comparison of Solar Sensitivity vs. Wind Only Case
Cumulative PVRR(d) of Net Benefit

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Note that the to-2050 results presented in Figure 2 above are the exact results that the Company provided in its workpapers (PROPRIETARY RMP Corrected EV2020 Second Supp Results Summary File - VOM adjusted 2-23-2018.xlsx). This chart demonstrates that when the full range of costs and benefits occurring between 2017 and 2050 are considered in the analysis, the Solar Sensitivity provides a significantly larger benefit to customers than the Combined Projects on a net present value basis. The Solar Sensitivity benefit exceeds the Combined Project benefit by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Not only are the Solar Projects more economic based on this analysis, they also involve less risk considering that the new Gateway D2 transmission segment would not be required, and that PPA terms would likely have provisions protecting ratepayers from capital cost overruns or other energy/PTC production performance risks associated with Company self-build projects.

C. INDEPENDENT EVALUATOR'S RFP EVALUATION

Q. WHAT IS YOUR INTERPRETATION OF THE UTAH AND OREGON IES' WIND RFP CONCLUSIONS?

A. My interpretation of both IEs' conclusions appears to be different than the Company's and, in some ways similar to the Oregon Staff's based on my review of the Oregon Staff's March 19, 2018 comments filed in Oregon Docket UM 1845.[19] The Oregon Staff commented that the Oregon IE had paired its recommendation for acknowledgement (February 16, 2018 IE Final RFP Report) with a recommendation for ratepayer protections, though the Oregon Staff did not agree that the RFP should be acknowledged.[20] In reply comments that PacifiCorp filed in Oregon on March 29, 2018, PacifiCorp disagreed with Staff's interpretation of the Oregon IE's recommendation.[21] Based on my review of the Oregon IE's Final RFP Report, I would agree that the Oregon IE acknowledged there were many risks associated with PacifiCorp's Combined Projects proposal, which led it to pair its acknowledgement recommendation with recommended ratepayer protection measures, and as I will discuss below, the Utah IE had similar concerns.

[19] http://edocs.puc.state.or.us/efdocs/HAC/um1845hac15355.pdf

[20] Id. at page 15. Oregon IE comments can be found in the Oregon IE Final RFP Report, February 16, 2018, Replacement Exhibit RTL-9SS, and public version at: http://edocs.puc.state.or.us/efdocs/HAH/um1845hah153253.pdf

[21] http://edocs.puc.state.or.us/efdocs/HAC/um1845hac152347.pdf

Q. DID THE UTAH OR OREGON IE EVALUATE THE WIND ONLY BIDS AGAINST ALL RESOURCE OPTIONS AVAILABLE TO PACIFICORP?

A. No, the IEs only compared the 2017R "Wind Only" bids against each other, relying on the Company's modeling, and did not do a thorough evaluation of other more current resource information. This was particularly the case given the expedited process and limited time they had available to conduct their evaluations. PacifiCorp itself conducted an IRP process over the course of a year, and only at the last minute presented its recommendations to spend over $2 billion on the Combined Projects. As indicated in the following quotes, the IEs admitted they did not conduct an evaluation determining if solar bids could possibly be even more cost effective than the Combined Projects, or if the Combined projects were the correct resources to acquire. The Utah IE noted:[22]

> …. it is not possible to determine if the wind-only resources offer the lowest reasonable cost without an integrated resource procurement and evaluation process that also includes solar and potentially other resources.

The Oregon IE acknowledged this in its Assessment of PacifiCorp's Final Draft 2017R Request for Proposals, August 10, 2017:[23]

> …. we do not address, and take no position on, two larger questions raised by this RFP, which are: 1) is Wyoming wind (paired with transmission) the "correct" resource to acquire? and 2) does this acquisition represent a "time-limited" opportunity of unique value to customers? To us, the first question will be answered in the IRP process and, if that process produces a "no" answer, then this RFP will be moot.

Q. PREVIOUSLY YOU RAISED CONCERNS ABOUT THE COMPANY'S CHANGE TO MODEL PTCS USING A NON-LEVELIZED REPRESENTATION AND ITS

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[22] Utah IE Final RFP Report (Redacted Version), February 2018, Section VI., page 71, https://pscdocs.utah.gov/electric/17docs/1703523/300421RedacFinRep2-27-2018.pdf.

[23] http://edocs.puc.state.or.us/efdocs/HAH/um1845hah143933.pdf, at page 2.

USE OF TERMINAL VALUE. DID THE IES COMMENT ABOUT THOSE ISSUES?

A. Yes, the IEs raised concerns about whether the change in PTC modeling and the terminal value could bias the results in favor of one resource over another, specifically they were concerned about the possibility of a preference to select BTAs and PacifiCorp's Benchmark Resources over PPA bids. However, those were not the only issues the IE's reviewed. In general, the following issues were examined:

1) The IEs reviewed sensitivity studies, including:
    a. A PTC Levelization study.
    b. A sensitivity concerning Cedar Springs. The IEs wanted to determine if it would be more economic if the full output of Cedar Springs were pursued as a PPA instead of as a BTA.
    c. A sensitivity to consider if additional network upgrade costs that were identified as part of the interconnection-restudy process and identified as late as February would still be economic.
2) The IEs investigated the impacts of data assumption corrections and updates (energy, sales tax) and interconnection queue/capability issues, that seemed to arise very late in the process.
3) The IEs suggested that some of PacifiCorp's Benchmark Resources be removed from the Shortlist, and certain PPAs be added instead. However, this request was rendered moot when PacifiCorp notified the IEs that the substitute PPAs could not be used because of interconnection queue issues.

Q. WHEN DID THE IES BECOME AWARE OF THE PTC LEVELIZATION ISSUE?

A. The Utah IE noted that it was reminded of the change when they compared results from PacifiCorp's initial Shortlist from November 2017 to the first version of the Final Shortlist they received in early January 2018. The Utah IE stated, "The IE questioned why PPAs would not be more competitive or even selected in the portfolios since the economics of BTAs and PPAs for initial shortlisting results were so competitive with a small differential in overall benefits on a $/MWH basis."[24] The Oregon IE asked PacifiCorp to run a sensitivity modeling PTCs using a non-levelized representation, which was discussed in its Final RFP Report to the Oregon PUC as follows:[25]

> … we asked the Company to run the SO Model with medium gas price and CO_2 inputs and levelize PTCs over the 30-year life of BTA and Benchmark bids, instead of treating them as earned. The results were more in line with the levelized cost models. The SO model selected the [redacted] PPA, the [redacted] PPA, and the [redacted] project.
>
> At this point, PacifiCorp made the observation that the non-levelized PTC selection would more closely reflect how they planned to pass PTC benefits through to ratepayers. While this was a reasonable assertion, we also noted that we had some concern that costs for their selection would not be levelized in real life but would, in fact, be front-loaded as well due to the way in which the costs for rate-based assets are recovered. Therefore, we had some concern that the front-loaded nature of rate recovery would cancel out the front-loaded benefits of the PTC recovery, and that the PPA-heavy portfolio was truly a better selection.

The Utah IE shared the same concern and described a solution to the IEs' concerns in written comments it sent to PacifiCorp and the Division on January 15, 2018, in which it recommended substituting a PPA bid option for two of the Company's BTAs in the final shortlist.[26]

> Based on the questions identified by the IEs, the last-minute revisions to the analysis to address errors in inputs, and uncertainty over the reasonableness of the evaluation methodology, Merrimack Energy feels that a logical solution would be to include the

[24] Utah IE Final RFP Report (Redacted Version), February 2018, at page 61.
[25] Oregon IE Final Public RFP Report, February 16, 2018, page 30.
[26] Utah IE Final RFP Report (Redacted Version), February 2018, at page 63.

[redacted] as an option to the [redacted] which total approximately [redacted].

The Company did not agree with the IEs, but around this same time, the issue with the interconnection queue limitation arose, and that led to PacifiCorp eliminating both the PPA option and PacifiCorp's McFadden Ridge Benchmark Resource from being considered for the Final Shortlist.

Q. WHAT WERE THE RESULTS OF THE IE SENSITIVITY PRIOR TO THE INTERCONNECTION QUEUE ISSUE ARISING?

A. PacifiCorp argued that its new approach to model PTCs using a non-levelized representation was appropriate and based on the SO model using the Medium Gas, Medium CO_2 case, PacifiCorp determined that the to-2036 results indicated that the BTA resource was more economic. However, when PacifiCorp performed the IE sensitivity, in which it modeled PTCs in the same way that it had when it developed the initial Shortlist, that is using levelized PTCs, the model favored the selection of PPAs over the BTAs.

Furthermore, PacifiCorp also provided the IEs additional results in which <u>all</u> costs, both capital and PTCs, were modeled using non-levelized representations, which is the alternative approach that I suggested for examining results earlier in this testimony. The following table shows the net benefit PVRR(d) results both through 2036 and through 2050 using the non-levelized capital, non-levelized PTC comparison of the portfolios developed using each of the modeling methodologies.[27]

[27] Oregon IE Final RFP Report, February 16, 2018, Replacement Exhibit RTL-9SS, page 31.

Table 6
IE Sensitivity – Net Benefit PVRR(d) Comparisons
Non-Levelized Capital, Non-Levelized PTC
Net (Benefits)/Costs
Millions of Dollars

Study Length	PAC BTA Portfolio	IE PPA Portfolio
2036	(95)	(161)
2050	(223)	(224)

The results indicate that the PPA heavy portfolio, developed using the levelized capital, levelized PTC methodology, is clearly more economic than the BTA heavy portfolio, developed using the Company's levelized Capital, Non-levelized PTC methodology, in the analysis through 2036, and arguably as economic as PacifiCorp's preferred BTA heavy portfolio in the analysis through 2050. Also, as I discussed previously, the results are also biased because of PacifiCorp's inclusion of a terminal value benefit, which the Company added to its BTA and Benchmark projects in 2050. The following table contains the results with the terminal value benefit removed, and again indicates that the PPA heavy portfolio is more economic than the BTA heavy portfolio in the analysis through 2050.[28]

Table 7
IE Sensitivity – Net Benefit PVRR(d) Comparisons
Terminal Value Benefit Removed

Study Length	PAC BTA Portfolio	IE PPA Portfolio
2050	(185)	(219)

[28] Oregon IE Final RFP Report, February 16, 2018, Replacement Exhibit RTL-9SS, page 32

Q. WHAT COMMENTS DID THE IES MAKE ABOUT THE RFP PROCESS ONCE THE INTERCONNECTION QUEUE ISSUE AROSE AND PACIFICORP DETERMINED BIDS HAD TO BE ELIMINATED BECAUSE THOSE BIDS REQUIRED COMPLETION OF ALL GATEWAY WEST AND SOUTH UPGRADES?

A. The Oregon IE expressed discomfort with the RFP process in this selection of comments.[29]

> The net result of these adjustments calls for consideration of the overall context of the RFP. …….. So this entire RFP really boiled down to two viable benchmarks and two third-party offers, meaning a lot of the analysis presented here was of questionable value.
>
> To be clear, the remaining viable offers were competitive offers, but were not the best the market could provide based on cost or risk, but for the transmission constraint issue.
>
> The real issue here is that PacifiCorp's procurement (in the form of this RFP) got out ahead of its resource and transmission planning. If PacifiCorp had identified this plan earlier, then all aspects of this work (IRP, transmission planning and resource acquisition) could have worked together in a more coherent fashion.

Q. DID THE IES PROVIDE MANY COMMENTS ABOUT THE COMPANY'S SOLAR SENSITIVITY STUDIES?

A. They each provided very limited comments about the solar sensitivities. The only comments about the solar sensitivity cases that the Utah IE made in its report was simply to acknowledge that PacifiCorp had performed those sensitivities and provided the IE with the results, and the Oregon IE also did little more than to acknowledge PacifiCorp's results.

Q. WHAT DO YOU CONCLUDE FROM YOUR REVIEW OF THE IE REPORTS?

[29] Oregon IE Final RFP Report, February 16, 2018, Replacement Exhibit RTL-9SS, pages 34-35. Note, for the sake of brevity, where identified, some of the Oregon IEs comments were excluded, though their inclusion would not have altered the point being made.

A. I conclude that the IEs found several problems with PacifiCorp's expedited RFP process, and they each acknowledged that they did not perform a broad evaluation of resources as typically would be performed in an IRP, to determine if a lower cost resource portfolio could be achieved. The Utah IE in fact was quite explicit in mentioning that it was not possible for it to "determine if the wind-only resources offer the lowest reasonable cost without an integrated resource procurement and evaluation process that also includes solar and potentially other resources."[30] Based on my review of the IE reports, I am even more concerned that there is a potential bias in the Company's modeling methodology, and given the possibility that the transmission isn't needed and that solar may be a better option, I simply do not believe the RFP shortlisted wind resources are necessarily the most optimal resources for the PacifiCorp System.

D. RISKS PACIFICORP DID NOT EVALUATE

Q. PACIFICORP CONDUCTED ANALYSES OF DIFFERENT PRICE-POLICY SCENARIOS, BUT DID IT CONDUCT ANY ANALYSES CONSIDERING THE POSSIBILITY OF HIGHER CAPITAL COSTS, LOWER WIND ENERGY AND PTC PRODUCTION, OR PROJECT DELAYS?

A. No, it performed no analysis of the impacts of any of these risks. In fact, at every step of the way, PacifiCorp has expressed confidence in its ability to complete BTA and Benchmark Resource projects on-time and on-budget, as well as its ability to forecast the amount of wind energy and PTCs that will be received. One example is found in Mr. Vail's supplemental direct testimony in which he stated the Company is very confident "that it

[30] Utah IE Final RFP Report (Redacted Version), February 2018, at page 71.

will deliver the Aeolus-to-Bridger/Anticline Line at or below its cost estimates."[31] Another example is in Ms. Crane's first supplemental testimony at line 209, in which she states, "We are confident that we will complete the Combined Projects before the 2020 deadline." However, the Utah and Oregon IEs do not appear to be as confident, and neither am I. The IEs expressed concern repeatedly throughout their final RFP reports about the possibility of project delays and that without protections, ratepayers could be subject to even higher costs with Benchmark Resources and BTAs than with PPAs. As a means of protecting ratepayers, the Utah IE expressed its apparent belief that a cap on project costs would be reasonable by stating, "PacifiCorp has indicated that most of the costs are fixed which would lead us to believe that PacifiCorp would be willing to stand by these cost estimates."[32]

Q. HAVE YOU PERFORMED ANY ANALYSES TO DETERMINE THE IMPACT OF THESE RISKS ON THE PURPORTED BENEFITS OF THE COMBINED PROJECTS?

A. Yes, I performed a set of analyses to investigate the impacts if a 5% increase in total capital cost, a 5% decrease in energy production, or a delay in the transmission projects were to occur.[33] For the transmission delay case, I assumed that the wind projects would be completed on time, but because of the transmission delay, I assumed that PacifiCorp would have to limit the wind generation output based on a rotating wind resource operating schedule that the Company stated it could follow and still be eligible to receive PTCs.

[31] Rick Vail Supplemental Direct and Rebuttal Testimony, January 16, 2018, at line 545.
[32] Utah IE Final 2017R RFP Report, (Redacted Version), February 2018, at page 41.
[33] Since I did not have access to the Company's SO and PaR models, these are OCS estimates based on the modeling results that the Company provided.

In the cost overrun case, I assumed there would be an overall cost increase of 5% stemming from possible cost overruns in the BTA and Benchmark Resource costs, and the Transmission Project costs, to the extent that those costs have not been finalized and are not entirely fixed.

In the case of the energy production sensitivity, I assumed that PacifiCorp's wind energy turbines would only be able to produce 95% of the annual energy that PacifiCorp estimated. I am aware that it would also be possible for the wind energy turbines to exceed expectations, or for the wind energy production to be higher than forecast in one year and lower than forecast in the next. However, I do not think it is unreasonable for purposes of a risk analysis assessment to determine potential impacts based on a 5% reduction, considering it is a scenario easily within the realm of possibility.

In the case of the transmission delay, I assumed that the Company would not be able to complete construction late in 2020, as the Company currently assumes, but instead would require an additional year during which time the wind projects would be limited to only 25% production based on a rotating production schedule that the Company states it could follow in order to be eligible to receive PTCs.[34]

Q. WHAT ARE THE RESULTS OF YOUR SENSITIVITY ANALYSES?

A. Table 8 compares net benefit PVRR(d) results of the different sensitivity cases that I analyzed for each price-policy case. I include the sensitivity results based on the to-2036 analysis, and I compare to what I refer to as the Base Case, which is the Alternative Approach that I presented in Table 2, which modeled capital cost revenue requirements

[34] In its response to UIEC 2.3(c), the Company states it hasn't conducted a complete financial evaluation on the round-robin plan that could be used in the event there is a substantial delay in completing the 500 kV transmission line. This sensitivity is one possibility of what a substantial delay might be.

and PTCs using a non-levelized representation. The last column is a final sensitivity case that I performed, in which all of the assumptions are modeled together in one case.

Table 8
PaR Stochastic Mean PVRR(d)
(Benefit)/Cost of New Wind
PTC and Capital Revenue Requirements Non-Levelized
To-2036 Study ($ million)

	Base Case	5% Cost Overrun	5% Reduced Production	25% Trans Delay	Combined
Low Gas, Zero CO_2	156	238	243	303	382
Low Gas, Medium CO_2	127	209	216	273	354
Low Gas, High CO_2	(30)	52	66	116	205
Medium Gas, Zero CO_2	(13)	69	83	137	225
Medium Gas, Medium CO_2	(51)	31	47	98	187
Medium Gas, High CO_2	(141)	(59)	(40)	10	104
High Gas, Zero CO_2	(262)	(180)	(154)	(100)	(1)
High Gas, Medium CO_2	(297)	(215)	(188)	(135)	(34)
High Gas, High CO_2	(388)	(306)	(274)	(226)	(120)

Q. PLEASE DISCUSS THE RESULTS OF YOUR SENSITIVITY ANALYSES?

A. As previously discussed, under the assumption that PTCs and capital revenue requirements use non-levelized representations, the Base Case indicates that two cases are completely uneconomic, and four other cases produce benefits that are less than $150 million, which does not provide sufficiently compelling support for proceeding with the projects. In the sensitivity analyses, all of results of the Low to Medium Gas/CO_2 price-policy cases indicate the Combined Projects are uneconomic. This is important because these are the possible futures that will have a good chance of occurring and should be given significant weight in any decision-making process. These sensitivity results indicate the Combined

Projects will not be economic unless gas and CO_2 costs are at the medium to high end of the spectrum.

IV. RESOURCE NEED

Q. IT APPEARS THE COMPANY HAS NOT DEMONSTRATED THE COMBINED PROJECTS ARE LEAST COST/LEAST RISK. HAS THE COMPANY DEMONSTRATED THERE IS A RELIABILITY NEED FOR THESE COMBINED PROJECTS THAT COULD NOT BE MET ANY OTHER WAY?

A. No, it has not. As I discussed in my direct testimony, the IRP indicated that the Combined Projects were not needed to satisfy either the Company's capacity requirements, or the Company's transmission reliability requirements. The Company has had a long-standing practice of allowing Front Office Transactions ("FOTs"), to meet a portion of its capacity needs, and PacifiCorp never stated in its June 30, 2017 Application that one of the goals of acquiring these new wind resources is to reduce its reliance on FOTs.

Q. THE COMPANY IS NOW CLAIMING THAT IT NEEDS TO HAVE THE TRANSMISSION PROJECTS IN SERVICE BY 2024, WHETHER IT IS APPROVED TO ACQUIRE THE NEW WIND RESOURCES IN 2020 OR NOT. HAS THE COMPANY PROVEN THIS NEED?

A. No. First, this statement of need was never discussed anywhere in the Company's June 30, 2017 Application. Had the Company's request been based on a resource need, the June 30, 2017 application would have had an entirely different emphasis. Mr. Vail emphasized this "resource need" in his supplemental direct and rebuttal testimony that he filed on January 16, 2018. For example, Mr. Vail stated, "To be clear, even if the Wind Projects are not approved, the Company's—and the region's—long-term transmission plans still call for the construction of the Aeolus-to-Bridger/Anticline Line (and some of the network upgrades) by 2024. Thus, the Company will need to construct this transmission line in the near future."[35] If the Company really believed the transmission line would have to be constructed by 2024, then it would have included the assumption that the D2 segment would be in-service in 2024 in the status quo case in its modeling analyses. Then, in its modeling analyses, all of its cases with the Combined Projects would simply have advanced the in-service date of the D2 segment by four years to 2020. However, that is not how the Company modeled the status quo case, as it made no assumption in that case that the Company would ever install the D2 segment.

There is no doubt that the Company has included the completion of this line by 2024 as part of its transmission plans for a few years. In its 2015 IRP report, PacifiCorp indicated its plans called for completion of the Segment D portion of the Gateway project by 2024.[36] However, 2024 is nothing more than just a target, not a mandatory date by which the Company will complete the transmission line, or that the line will ever be completed for that matter. For instance, in PacifiCorp's 2008 IRP, PacifiCorp included the 500 kV line between Windstar and Populus in its action plan with an assumed in-service date of 2014,[37] and in its 2013 IRP, PacifiCorp discussed its plans for the same line, but with a new assumed in-service date of 2019.[38]

[35] Rick Vail Supplemental Direct and Rebuttal Testimony, January 16, 2018, at line 265.
[36] https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/PacifiCorp_2015IRP-Vol1-MainDocument.pdf, March 31, 2015, at page 57.
[37] https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2008IRP/2008IRP_Vol1_5-28-09.pdf, May, 28, 2009, at page 258-259.
[38] https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacifiCorp-2013IRP_Vol1-Main_4-30-13.pdf April 30, 2013, at page 65.

Q. WHAT EXPLANATION HAS THE COMPANY GIVEN IN ITS IRPS CONCERNING THE REVISIONS TO ITS GATEWAY IN-SERVICE DATE PLANS?

A. In its 2015 IRP, PacifiCorp provided no sense of critical need when it explained why the Gateway segments in-service dates have been revised, when it explained:[39]

> Finally, the timing of segments is regularly assessed and adjusted. While permitting delays have played a significant role in the adjusted timing of some segments (e.g., Gateway West and Gateway South), the Company has been proactive in deferring in-service dates as needed due to permitting schedules, moderated load growth, changing customer needs, and system reliability improvements.
>
> The Company will continue to adjust the timing and configuration of its proposed transmission investments based on its ongoing assessment of the system's ability to meet customer needs and its compliance with mandatory reliability standards.

An almost identical statement is included in the Company's most recent 2017 IRP.[40] Based on this review, I do not believe that PacifiCorp has established that there is a critical need for the proposed transmission segments, such that they will have to be added by 2024, whether the wind resources are acquired or not.

Q. PACIFICORP STATED THAT MODERATING LOAD GROWTH HAS PLAYED A ROLE IN ADJUSTING THE TIMING OF NEED FOR THE NEW TRANSMISSION. HAVE YOU ALSO REVIEWED THE TRENDS IN PACIFICORP'S LOAD GROWTH?

A. Yes, I have examined trends in PacifiCorp's peak demand forecasts both in Utah and in Wyoming as provided in PacifiCorp's IRP Reports from the 2007 IRP through the 2017

[39] 2015 IRP at page 56.
[40] 2017 IRP at page 70.

IRP. The following two graphs compare the forecasts for each state over time and demonstrate a significant flattening of demand requirements over time.

Figure 3
Wyoming Jurisdictional Load Forecast (MW)

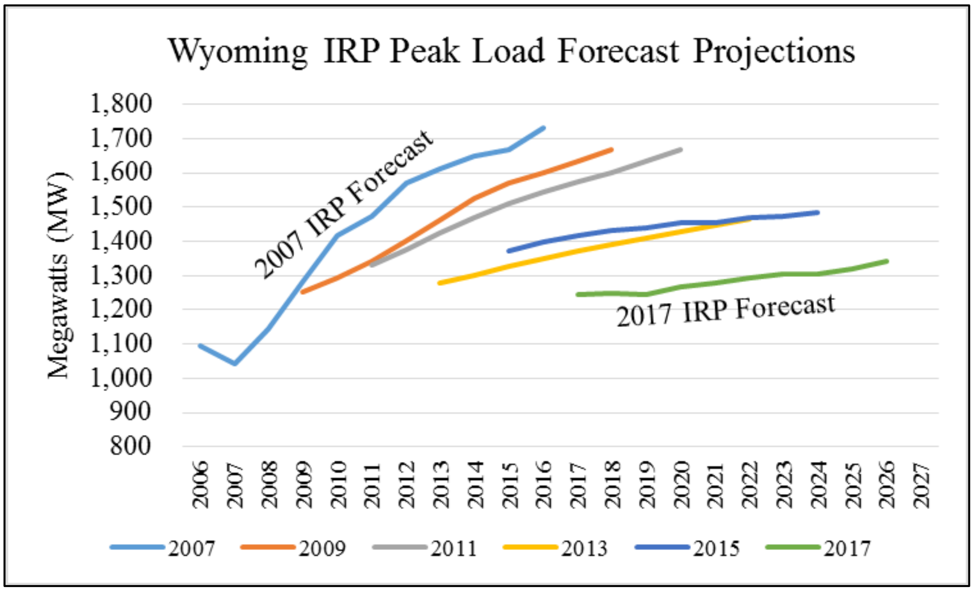
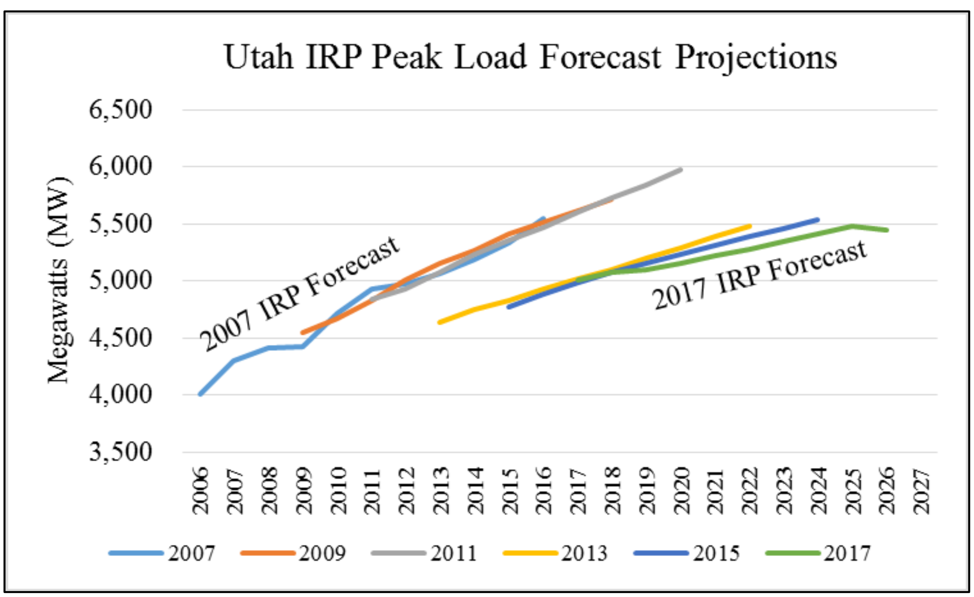


Figure 4
Utah Jurisdictional Load Forecast (MW)



The 2017 peak demand projections are still below the earlier projections that had been developed close in time to when the Gateway line had first been proposed by PacifiCorp, and given that the projections have even trended lower in this proceeding, it certainly does not appear that load growth will be a significant driver in PacifiCorp's need to construct the new transmission projects for some time to come.

V. RATEPAYER PROTECTIONS

Q. BESIDES CONDITIONS THAT YOU PRESENT, DO OTHER OFFICE WITNESSES RECOMMEND OTHER RATEPAYER PROTECTIONS?

A. Yes, Ms. Donna Ramas presents additional protections, including the Office's recommendation that the Company's RTM proposal should be rejected, and Mr. Bela Vastag recommends capping the cost of the Combined Projects based on the Office's concern about a new Multi State Process ("MSP").

Q. HAS PACIFICORP ACKNOWLEDGED A WILLINGNESS TO ACCEPT ANY RISKS?

A. Yes, at line 207 of her supplemental direct and rebuttal testimony, Ms. Crane stated, "While we do not believe it is appropriate for the Company to absorb risks beyond its control, we are prepared to accept risks associated with our performance." In my opinion, Ms. Crane has understated the performance risks that the Company should absorb. It must accept responsibility, for example, for the cost of delays that occur as a result of one of its contractors that is unable to meet its obligations and cause the overall project to be delayed. Another example relates to the Company's plans to operate the wind resources in a "round robin scheme" if the transmission projects are delayed. In response to OCS 16.7, the Company explained how it intends to ensure the wind resources would be eligible to receive PTC benefits in the event the new transmission projects are delayed. The Company essentially explained that if the transmission delay is caused by the performance of one of its contractors, PacifiCorp should not be held responsible for that. I disagree, and I believe that PacifiCorp should be responsible for the performance of all of its contractors. As between the ratepayer and PacifiCorp, PacifiCorp is the party with the contracting, managing and oversight responsibility and should assume full responsibility for the actions of its contractors. I recommend that the Commission require PacifiCorp to assume all responsibility for the successful completion of the Combined Projects, based on more stringent conditions that I outline below.

Q. IN YOUR DIRECT TESTIMONY YOU PRESENTED A RATEPAYER PROTECTION TO CAP THE COST OF PROJECT IN RATES. ARE YOU STILL RECOMMENDING THAT RATEPAYER PROTECTION?

A. Yes, however, given the additional findings that I have discussed in this testimony, such as the fact that new wind resources are based strictly on economics, and not reliability, and given that there are other resources that are more economic including solar resources, I believe additional ratepayer protections are required. My primary recommendation remains that these projects should be denied, but in the event the Commission decides to approve the Company's requests, I recommend the Commission adopt the following additional conditions:

- PacifiCorp should be limited to recovery of capital investment for the Combined Projects to the amounts that it included in its corrected second supplemental direct testimony filing. In other words, the Company should not be authorized to recover anything more than the lesser of the amount the Company identified to construct the Combined Projects or the actual completed cost of the Combined Projects.

- PacifiCorp should be limited to recovery of future O&M and capital expenditures for the approved repowering projects to the amounts that it included in its corrected second supplemental direct testimony filing. In other words, these costs should be capped to the amounts the Company assumed for these costs in its corrected testimony analysis for the Utah jurisdiction.

- In addition, PTCs and energy benefits should be guaranteed at 95% of the amounts PacifiCorp assumed in its corrected second supplemental direct testimony filing for the life of the wind projects. I do not believe this is unreasonable as PacifiCorp has expressed a high degree of confidence in its ability to forecast the amount of wind energy that the projects will produce, and 95% is a reasonable margin to allow for some forecasting error.

- PacifiCorp has computed all analyses based on the assumptions that retail ratepayers will ultimately only have to pay 88% of the capital costs because the remaining 12% will be assigned to wholesale transmission customers through OATT charges. I recommend that the Commission cap the allocation to retail customers at 88% of the capital related revenue requirements.

Q. WHAT IS THE AMOUNT THAT YOU RECOMMEND CAPPING THE COST OF THE COMBINED PROJECTS ON A UTAH JURISDICTIONAL BASIS?

A. The following table identifies the amount the Company identified to construct the Combined Projects.

Table 9
Project In-Service Capital
$ Millions

	In-Service Capital[41]	**After 12% Transmission Contribution**	**Utah Jurisdiction**[42]
Transmission	[redacted]	[redacted]	[redacted]
230 kV Upgrades	[redacted]	[redacted]	[redacted]
Total Transmission	[redacted]	[redacted]	[redacted]
Ekola Flats	[redacted]	[redacted]	[redacted]
TB Flats	[redacted]	[redacted]	[redacted]
Cedar Springs	[redacted]	[redacted]	[redacted]
Uinta	[redacted]	[redacted]	[redacted]
Total Wind	[redacted]	[redacted]	[redacted]
Combined Projects	[redacted]	[redacted]	[redacted]

The amount the project should be capped at is [redacted] million on a Utah Jurisdictional basis.

Q. ARE THE CONDITIONS ABOVE CONSISTENT WITH THE RECOMMENDATIONS THAT THE IES MADE IN THEIR FINAL REPORTS?

A. Yes, as I mentioned previously, the Utah IE noted that the Company expressed confidence in its ability to complete the projects within budget because it stated that most of the costs are fixed. This in turn led the Utah IE to state that this "would lead us to believe PacifiCorp would be willing to stand by these costs estimates."[43] Furthermore, the Oregon IE devoted a section entitled Additional Recommendations to Protect Ratepayers, which it stated was to "help protect ratepayers from bearing undue risk" and "ensure they receive the benefits promised during the RFP." In essence, the Oregon IE recommended that similar conditions

[41] Chad A. Teply Confidential Exhibit RMP (CAT-5SS), New Wind Initial Capital Annual Details.
[42] Joelle R. Steward's Exhibit RMP__(JRS-2SS) uses the SG allocation factor of 42.6283%.

[43] Utah IE Final 2017R RFP Report, February 2018, at page 41.

be imposed to those that I recommended including holding PacifiCorp to be allowed to recover just the amount of capital and O&M that the Company outlined in its corrected second supplemental direct testimony for all of the Combined Projects, and to hold ratepayers harmless such that ratepayers would receive the full PTC benefits that PacifiCorp identified in its economic analyses.[44]

VI. CONCLUSIONS

Q. PLEASE STATE YOUR CONCLUSIONS.

A. Based on my analysis I do not believe the Company has proven that the Combined Projects will most likely result in the acquisition, production, and delivery of electricity at the lowest reasonable cost and least risk possible as required by Utah Code §54-17-302(3)(c). The Company's modeling analyses do not provide convincing evidence that these projects would be economic. In this and in my direct testimony, I have identified problems in both the Company's to-2036 and its to-2050 economic analyses. The potential inaccuracy of the modeling results places significant risk on the ratepayer, particularly given that the projects can swing from being economic to uneconomic depending on the modeling method used.

I have also reviewed the Company's Solar Only Sensitivity case and found that when based strictly on the Company's own to-2050 results, the Solar projects are more economic than the Combined Projects. Furthermore, I evaluated the to-2036 study results, and found that depending on how the PTC and capital revenue requirements are modeled, Solar Only resources could be more economic than the Combined Projects. I found that the only case in which the Combined Projects were more economic than the Solar Only

[44] Oregon IE Final RFP Report, February 16, 2018, Replacement Exhibit RTL-9SS, page 4.

resources was in the case in which the Company revised its methodology to use a non-levelized PTC representation.

I also do not believe the Company has considered all risks that could affect the Combined Projects including the possibility of cost overruns, lower wind energy production and PTC benefits. Based on the risk analysis I performed, small changes in assumptions could easily lead to some of the price-policy cases becoming uneconomic. For the most part, I found that when compared to the Status Quo case, the Combined Projects would only be economic in the Moderate to High Gas/CO_2 cases when additional risks were considered such as small cost overruns. Furthermore, because of transmission queue issues and the modeling change going from using a levelized to a non-levelized PTC representation, the Company's selection process is biased against selecting PPA projects in favor of selecting self-build and BTA projects. PPA projects would protect ratepayers from cost, energy production, and PTC risks.

Based on these concerns, my primary recommendation is that the Commission should deny the Company's request. However, if the Commission is inclined to permit the Company to proceed with building the Gateway D2 segment and acquire about 1,300 MW in new wind project capacity, I recommend that the Commission impose a set of ratepayer protection conditions. In addition to the conditions that I have proposed, Office witnesses Ramas and Vastag, presents other conditions in their testimonies.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.