ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W. North Temple, Suite 320
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February 23, 2018

VIA ELECTRONIC FILING

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84114

Attention: Gary Widerburg
Commission Secretary

RE: Docket No. 17-035-40
Application for Approval of a Significant Energy Resource Decision and Voluntary Request for Approval of Resource Decision – Corrected Testimony and Exhibits

On January 16, 2018, Rocky Mountain Power (the "Company") filed its supplemental direct and rebuttal testimony to update the filing for the results of the 2017R Request for Proposals ("2017R RFP") in accordance with the procedural schedule issued July 27, 2107 in the above referenced docket. On February 16, 2018 the Company filed its second supplemental testimony to update the filing for the 2017R RFP final shortlist to reflect the results of the interconnection restudy process and new system impact studies ("SISs").

While drafting a response to a data request, the Company identified an error in its treatment of certain wind project costs that affect the net economic benefits of the Combined Projects as derived from Planning and Risk model ("PaR") studies. The data request was submitted in response to the Company's January 16, 2018 supplemental direct and rebuttal filing and asked if certain wind project costs modeled as variable operations and maintenance costs ("VOM") were included in the Company's 2036 and 2050 studies.

These VOM costs include two types of costs for the proposed new wind facilities—Wyoming wind tax costs and wind integration costs. The Company subsequently confirmed that these costs were accurately captured in System Optimizer ("SO") model studies, which were used to produce economic analysis through 2036. However, application of these costs were not accurately captured in PaR studies used in the economic analysis through 2036 and through 2050. The misapplication of these costs is present in the economic analysis supporting the Company's supplemental direct and rebuttal and second supplemental filings.

Both elements of the VOM costs were included as a project cost in the PaR studies used to develop economic analysis through 2036. However, PaR was also configured to include incremental regulation reserve requirements associated with the new wind projects. The wind integration cost element of VOM captures the cost of holding incremental regulation reserves needed to integrate the new wind facilities, and thus, wind integration costs were being double counted in the PaR studies. The SO model cannot be configured to capture these incremental regulation reserve requirements, and thus, inclusion of wind integration costs in the SO model was appropriate. Eliminating the wind integration cost element of VOM in the PaR studies through 2036 eliminates double counting and improves customer benefits by $22 million in all price-policy scenarios in the Company's supplemental direct and rebuttal filing and by $24 million in all price-policy scenarios in the Company's second supplemental filing.

The PaR studies used to develop the economic analysis through 2050 did not include any of the VOM cost elements described above. Considering that PaR was configured to hold incremental regulation reserves needed to integrate the new wind facilities, the only element of the VOM costs that should have been included in these studies is the cost associated with the Wyoming wind tax. Including the cost of the Wyoming wind tax in PaR studies used to develop the economic analysis through 2050 reduces customer benefit by $26 million in all price-policy scenarios in the Company's supplemental direct and rebuttal filing and by $29 million in all price-policy scenarios in the Company's second supplemental filing.

As noted above, these adjustments do not apply to SO model results, which appropriately include the wind integration cost element of VOM costs. Considering that the SO model was used to make bid-selections for the 2017R RFP and is unaffected by these corrections, selection of winning bids to the 2017R RFP final shortlist is unaffected. Moreover, upon discovering the misapplication of certain VOM costs, all calculations in the Company's filing were reviewed to ensure that, once the corrections described above were made, all project-cost elements and projected benefits were appropriately flowing into the economic analysis. The Company did not find any other issues during this review.

To ensure the record in this proceeding is accurate and to correct the single error discussed above, Rocky Mountain Power hereby submits replacement pages of testimony (clean and redline versions) for witnesses Rick T. Link and Cindy A. Crane as well as corrected exhibits and workpapers for Mr. Link as follows:

- Supplemental Direct and Rebuttal Testimony
  - Exhibit RMP__(RTL-4SD)
  - Exhibit RMP__(RTL-5SD)
  - Confidential Workpaper Table 2-SD, Table 3-SD, Figure 5 FSL Results Summary File - VOM Adjusted 2.21.18
- Second Supplemental Direct Testimony
  - Exhibit RMP__(RTL-2SS)
  - Exhibit RMP__(RTL-3SS)
  - Confidential Workpaper EV2020 Second Supp Results Summary File - VOM adjusted

The only change reflected in these replacement pages, exhibits, and workpapers is the treatment of the VOM cost elements discussed above.

Also, in the Company's second supplemental filing, Mr. Link provided the Oregon

Independent Evaluator ("IE") Assessment of PacifiCorp's Final Draft 2017R Request for Proposals dated August 10, 2017 as Exhibit RMP___(RTL-9SS). The Company received the final Oregon Independent Evaluator Final Report on PacifiCorp's 2017R Request for Proposals on February 16, 2018. Included in this filing is a replacement Highly Confidential Exhibit RMP___(RTL-9SS) that is now appended with the final Oregon IE report and should replace the exhibit filed with the Company's second supplemental filing in its entirety.

Rocky Mountain Power respectfully requests that all formal correspondence and requests for additional information regarding this filing be addressed to the following:

By E-mail (preferred): datarequest@pacificorp.com
Jana.saba@pacificorp.com
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By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232

Informal inquiries may be directed to Jana Saba at (801) 220-2823.

Sincerely,

Joelle Steward
Vice President, Regulation

<u>CERTIFICATE OF SERVICE</u>

Docket No. 17-035-40

I hereby certify that on February 23, 2018, a true and correct copy of the foregoing was served by electronic mail and/or overnight delivery to the following:

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Katie Savarin

Katie Savarin
Coordinator, Regulatory Operations

Corrected Supplemental Direct and Rebuttal Testimony

Cindy A. Crane

In rebuttal testimony, the Company shows the Combined Projects are necessary to meet an identified resource need and present no more risk than typical utility investments. The Company will manage future potential risks either through the off-ramps built into the projects or by seeking additional direction from the Commission before or during project implementation.

SUPPLEMENTAL DIRECT TESTIMONY

Q. Based on the results of the 2017R RFP and the Company's updated analysis of benefits, costs, and risks, do the Combined Projects satisfy the public interest standard?

A. Yes. The Combined Projects are the least-cost, least-risk path available to serve the Company's customers by meeting both near-term and long-term needs for additional resources. Mr. Rick T. Link's supplemental direct testimony and updated economic analysis demonstrates increased customer benefits of $151 million in the medium case through 2050 (as compared to $137 million in the original filing), and a range of $333 million to $349 million in the medium case through 2036. As described further by Mr. Link, 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. Moreover, the updated economic analysis demonstrates the Combined Projects provide net customer benefits under all scenarios studied through 2036, and in seven of the nine scenarios through 2050.

The fact that the Combined Projects will provide customer benefits significantly

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The fact that the Combined Projects will provide customer benefits significantly

Corrected Second Supplemental Direct Testimony

Cindy A. Crane

viable without Energy Gateway South, a PacifiCorp transmission project that is not scheduled to be built before the expiration of production tax credits ("PTCs") in 2020. McFadden Ridge II has a queue position higher than the cutoff point, so the Company removed it from the final shortlist.

Second, the restudy identified 1,510 MW of total interconnection capacity for projects in eastern Wyoming, up from 1,270 MW. The Company updated its System Optimizer ("SO") model simulations taking into account these findings. The SO model continued to select TB Flats I and II, Cedar Springs, and Uinta, but replaced McFadden Ridge II with Ekola Flats for the 2017R RFP final shortlist now that more interconnection capacity was identified.

Q. Did the Company update its SO and Planning and Risk ("PaR") studies to reassess the economic benefits of the Combined Projects?

A. Yes. As explained by Company witness Mr. Link, the Company updated the SO and PaR studies for all nine price-policy scenarios. Mr. Link's updated economic analysis demonstrates increased customer benefits of $167 million in the medium case through 2050 (as compared to $137 million in the original filing and $151 million in the first supplemental filing), and an increased benefit range of $357 million to $405 million in the medium case through 2036. Moreover, the updated economic analysis demonstrates the Combined Projects continue to provide net customer benefits under all scenarios studied through 2036, and in seven of the nine scenarios through 2050.

Q. Did the Company prepare new sensitivity analyses to test the likelihood of achieving these economic benefits?

A. Yes, as in the first supplemental filing, the Company updated several different scenarios viable without Energy Gateway South, a PacifiCorp transmission project that is not scheduled to be built before the expiration of production tax credits ("PTCs") in 2020. McFadden Ridge II has a queue position higher than the cutoff point, so the Company removed it from the final shortlist.

Second, the restudy identified 1,510 MW of total interconnection capacity for projects in eastern Wyoming, up from 1,270 MW. The Company updated its System Optimizer ("SO") model simulations taking into account these findings. The SO model continued to select TB Flats I and II, Cedar Springs, and Uinta, but replaced McFadden Ridge II with Ekola Flats for the 2017R RFP final shortlist now that more interconnection capacity was identified.

Q. Did the Company update its SO and Planning and Risk ("PaR") studies to reassess the economic benefits of the Combined Projects?

A. Yes. As explained by Company witness Mr. Link, the Company updated the SO and PaR studies for all nine price-policy scenarios. Mr. Link's updated economic analysis demonstrates increased customer benefits of $~~196~~ 167 million in the medium case through 2050 (as compared to $137 million in the original filing and $~~177~~ 151 million in the first supplemental filing), and an increased benefit range of $~~333~~ 357 million to $405 million in the medium case through 2036. Moreover, the updated economic analysis demonstrates the Combined Projects continue to provide net customer benefits under all scenarios studied through 2036, and in seven of the nine scenarios through 2050.

Q. Did the Company prepare new sensitivity analyses to test the likelihood of achieving these economic benefits?

Corrected Supplemental Direct and Rebuttal Testimony

Rick T. Link

and McFadden Ridge II are company-built facilities, totaling 500 MW and 109 MW, respectively.

The results of the 2017R RFP and the extensive modeling that supports it confirm that the Combined Projects are the least-cost, least-risk path available to serve the company's customers by meeting both near-term and long-term needs for additional resources. My supplemental direct testimony explains the following:

- The Combined Projects provide net customer benefits under all scenarios studied through 2036, and in seven of the nine scenarios through 2050.
- Customer benefits increase to $151 million in the medium case through 2050 (as compared to $137 million in the original filing), and range from $333 million to $349 million in the medium case through 2036.
- The analysis reflects changes in federal tax law that were enacted in December 2017, and updated best-and-final pricing from bidders received December 21, 2017, after the federal tax law changes were known.
- 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.
- Sensitivity analysis shows substantial benefits of the Combined Projects persist when paired with PacifiCorp's wind repowering project and are not displaced when considering the potential procurement of solar PPA bids submitted into the on-going RFP for solar resources, the 2017S RFP.

Table 2-SD Updated SO Model and PaR PVRR(d) (Benefit)/Cost of the Combined Projects ($ million)

Price-Policy Scenario	SO Model PVRR(d)	PaR Stochastic Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Low Gas, Zero CO2	($145)	($126)	($131)
Low Gas, Medium CO2	($186)	($146)	($152)
Low Gas, High CO2	($297)	($280)	($294)
Medium Gas, Zero CO2	($306)	($268)	($280)
Medium Gas, Medium CO2	($343)	($333)	($349)
Medium Gas, High CO2	($430)	($409)	($428)
High Gas, Zero CO2	($619)	($531)	($557)
High Gas, Medium CO2	($636)	($561)	($588)
High Gas, High CO2	($696)	($627)	($658)

Over a 20-year period, the Combined Projects reduce customer costs in all nine price-policy scenarios. This outcome is consistent in both the SO model and PaR results. Under the central price-policy scenario, assuming medium natural-gas prices and medium CO_2 prices, the PVRR(d) net benefits range between $333 million, when derived from PaR stochastic-mean results, and $349 million, when derived from PaR risk-adjusted results.

Q. What trends do you observe in the modeling results across the different price-policy scenarios?

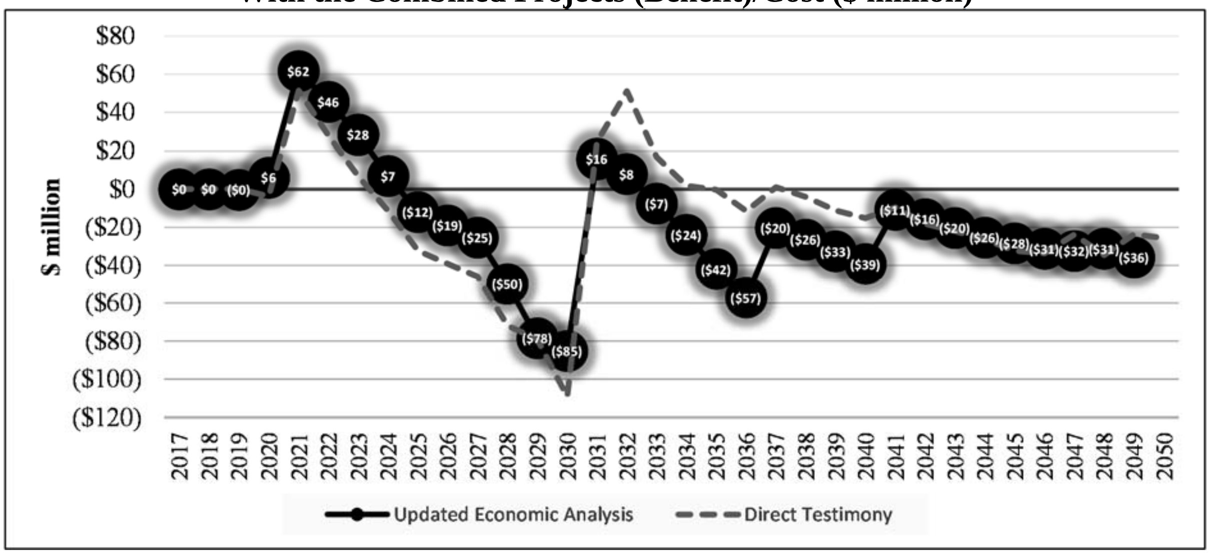
A. Projected system net benefits increase with higher natural-gas price assumptions, and similarly, increase with higher CO_2 price assumptions. Conversely, system net benefits decline when low natural-gas prices and low CO_2 prices are assumed. This trend holds annual data over the period 2017 through 2050 that was used to calculate the PVRR(d) results shown in the table are provided as Exhibit RMP__(RTL-5SD).

Table 3-SD. Updated Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of the Combined Projects ($ million)

Price-Policy Scenario	Annual Revenue Requirement PVRR(d)
Low Gas, Zero CO2	$195
Low Gas, Medium CO2	$159
Low Gas, High CO2	($79)
Medium Gas, Zero CO2	($34)
Medium Gas, Medium CO2	($151)
Medium Gas, High CO2	($275)
High Gas, Zero CO2	($411)
High Gas, Medium CO2	($453)
High Gas, High CO2	($559)

When system costs and benefits from the Combined Projects are extended out through 2050, covering the full depreciable life of the owned wind projects included in the 2017R RFP final shortlist, the Combined Projects reduce customer costs in seven out of nine price-policy scenarios. Customer benefits range from $34 million in the medium natural-gas, zero CO_2 scenario, to $559 million in the high natural-gas, high CO_2 scenario. Under the central price-policy scenario, assuming medium natural-gas prices and medium CO_2 prices, the PVRR(d) benefits of the Combined Projects are $151 million. The Combined Projects provide significant customer benefits in all price-policy scenarios, and the net benefits are unfavorable only when low natural-gas prices revenue requirement shown in the figure reflects updated costs, including capital revenue requirement (*i.e.*, depreciation, return, income taxes, and property taxes), O&M expenses, the Wyoming wind-production tax, and PTCs. The project costs are netted against updated system impacts from the Combined Projects, reflecting the change in NPC, emissions, non-NPC variable costs, and system fixed costs that are affected by, but not directly associated with, the Combined Projects.

Figure 5-SD Updated Total-System Annual Revenue Requirement With the Combined Projects (Benefit)/Cost ($ million)



The data shown in this figure for the updated economic analysis have the same basic profile as the data from the original economic analysis summarized in my direct testimony. This profile shows that despite a reduction in PTC benefits associated with changes in federal tax law, the reduced costs from winning bids from the 2017R RFP continue to generate substantial near-term customer benefits, reduce the magnitude and shorten the duration over which costs increase after federal PTCs for new wind resources expire, and continue to contribute to customer benefits over the long term.

The year-on-year reduction in net benefits from 2036 to 2037 is driven by the company's conservative approach to extrapolate benefits from 2037 through 2050 scenarios. The results are shown alongside the benchmark study in which the Combined Projects were evaluated without solar PPA bids.

Table 4-SD Solar Sensitivity with Solar PPAs Included in lieu of the Combined Projects (Benefit)/Cost ($ million)

	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
Medium Gas, Medium CO2			
SO Model	($334)	($343)	$9
PaR Stochastic Mean	($222)	($333)	$111
PaR Risk Adjusted	($233)	($349)	$116
Low Gas, Zero CO2			
SO Model	($206)	($145)	($61)
PaR Stochastic Mean	($141)	($126)	($15)
PaR Risk Adjusted	($148)	($131)	($17)

In the medium natural gas, medium CO_2 price-policy scenario, a portfolio with the Combined Projects delivers greater customer benefits relative to a portfolio that adds solar PPA bids without the Combined Projects. Customer benefits are greater when the resource portfolio includes the Combined Projects without solar PPA bids by $116 million in the medium natural gas, medium CO_2 price-policy scenario based on the risk-adjusted PaR results. In the low natural gas, zero CO_2 price-policy scenario, the portfolio with solar PPA bids and without the Combined Projects has higher net customer benefits relative to a portfolio containing just the Combined Projects. The increase in net benefits in the solar PPA portfolio is $17 million based on the risk-adjusted PaR results.

Q. What were the results of the solar sensitivity where solar PPA bids are pursued with the Combined Projects?

A. Table 5-SD summarizes PVRR(d) results for the solar sensitivity where solar PPA bids are assumed to be pursued along with the proposed investments in the Combined Projects. This sensitivity was developed using SO model and PaR simulations through 2036 for the medium natural gas, medium CO_2 and the low natural gas, zero CO_2 price-policy scenarios. The results are shown alongside the benchmark study in which the Combined Projects were evaluated without solar PPA bids.

Table 5-SD Solar Sensitivity with Solar PPAs Included
With the Combined Projects (Benefit)/Cost ($ million)

	Sensitivity PVRR(d)	**Benchmark PVRR(d)**	**Change in PVRR(d)**
Medium Gas, Medium CO2			
SO Model	($602)	($343)	($259)
PaR Stochastic Mean	($482)	($333)	($149)
PaR Risk Adjusted	($504)	($349)	($155)
Low Gas, Zero CO2			
SO Model	($286)	($145)	($141)
PaR Stochastic Mean	($217)	($126)	($91)
PaR Risk Adjusted	($227)	($131)	($96)

When the solar PPAs are pursued in addition to the Combined Projects, the total benefits increase, but are diluted (*i.e.*, the aggregate net benefits are less than the sum of the benefits for the cases where Combined Projects or solar PPAs are pursued independently).

Q. What conclusions can you draw from these solar sensitivity analyses?

A. These sensitivities demonstrate that should the company choose to pursue solar bids facilities assuming they continue to operate within the limits of their large generator interconnection agreements (“LGIAs”).

Q. What were the results of the wind-repowering sensitivity?

A. Table 6-SD summarizes PVRR(d) results for this wind-repowering sensitivity. This sensitivity was developed using SO model and PaR simulations through 2036 for the medium natural-gas, medium CO_2 and the low natural-gas, zero CO_2 price-policy scenarios. The results are shown alongside the benchmark study in which the Combined Projects were evaluated without wind repowering.

Table 6-SD Wind-Repowering Sensitivity (Benefit)/Cost ($ million)

	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
Medium Gas, Medium CO2			
SO Model	($541)	($343)	($198)
PaR Stochastic Mean	($497)	($333)	($164)
PaR Risk Adjusted	($520)	($349)	($171)
Low Gas, Zero CO2			
SO Model	($313)	($145)	($169)
PaR Stochastic Mean	($277)	($126)	($152)
PaR Risk Adjusted	($290)	($131)	($159)

In the wind-repowering sensitivity, customer benefits increase significantly when the wind repowering project is implemented with the Combined Projects in both the medium natural-gas, medium CO_2, and the low natural-gas, zero CO_2 price-policy scenarios. These results demonstrate that customer benefits not only persist, but also increase, if both the wind-repowering project and the Combined Projects are completed.

will likely be different from the forward price curve, but if the forecast is unbiased, *i.e.*, that it is equally likely that the actual future prices are higher or lower than the forecasted prices, [] the best approach is to simply act today on its forecast as the best indicator of future outcomes." *In the Matter of the Voluntary Request of Rocky Mountain Power for Approval of Resource Decision to Acquire Natural Gas Resources*, Docket No. 12-035-102, Pre-Filed Direct Testimony of Douglas D. Wheelwright on Behalf of Utah Division of Public Utilities at lines 326-330 (Mar. 5, 2013). DPU noted that if "one had information today that the longer-term future was likely to be different from the above forecast, then the above analysis could be invalidated by the additional information." *Id.* at 330-332. In this case, however, there is no additional information indicating that the longer-term future is likely to be different from the OFPC and therefore, according to the DPU's prior analysis, the "best approach" is to act today based on the OFPC.

Q. How does the company use each of the price-policy scenarios in its analysis?

A. The price-policy scenario assuming medium natural-gas prices and medium CO_2 prices represents the central forecast, around which the impact of lower or higher price assumptions can be evaluated. In the company's updated economic analysis, the PVRR(d) net benefit of the Combined Projects derived from the central price-policy scenario is $151 million when calculated from projected nominal system costs through 2050. This outcome indicates that, when central price-policy assumptions are used, there is a reasonably sized cushion in the PVRR(d) results allowing for some erosion of the favorable economics should long-term natural-gas prices and CO_2 prices end up lower than what is assumed in this scenario. The other price-policy scenarios are useful

Q. Mr. Peaco claims that the expected customer benefits are modest relative to the overall project costs and that there is very little certainty that customers will see significant, if any, cost savings. (Peaco Direct, line 316-318.) Mr. Hayet criticizes the Combined Projects because, under most scenarios, he claims they present modest benefits relative to the company's total revenue requirement. (Hayet Direct, lines 284-297.) Please respond.

A. First, Mr. Peaco mischaracterizes the relationship between the cost and benefits of the Combined Projects by comparing the up-front investment cost to the *net* benefits of the project. This artificially makes it appear that customer benefits are relatively small in relation to the investment required to deliver those benefits, when in fact, the gross benefits from the projects are actually greater than total project costs.

For instance, in the updated economic analysis, the PVRR(d) results calculated from the change in system costs through 2050 assuming medium natural-gas and medium CO_2 prices show a $151 million *net* customer benefit from the Combined Projects. This is based on present-value project costs, including changes to run-rate operating costs, totaling $1.50 billion. The present value of customer benefits, including federal PTC benefits, for this price-policy scenario is $1.65 billion, which is $151 million greater than the present value of project costs. In fact, the present value of customer benefits among all nine price-policy scenarios ranges between $1.30 billion and $2.06 billion. In nearly all scenarios, the present value of customer benefits exceed the present value of customer costs.

Second, the fact the total expected benefits are small relative to the company's total revenue requirement means little in this case. It is hard to imagine a resource and McFadden Ridge II are company-built facilities, totaling 500 MW and 109 MW, respectively.

The results of the 2017R RFP and the extensive modeling that supports it confirm that the Combined Projects are the least-cost, least-risk path available to serve the company's customers by meeting both near-term and long-term needs for additional resources. My supplemental direct testimony explains the following:

- The Combined Projects provide net customer benefits under all scenarios studied through 2036, and in seven of the nine scenarios through 2050.
- Customer benefits increase to $~~177~~ 151 million in the medium case through 2050 (as compared to $137 million in the original filing), and range from $~~311~~ 333 million to $~~343~~ 349 million in the medium case through 2036.
- The analysis reflects changes in federal tax law that were enacted in December 2017, and updated best-and-final pricing from bidders received December 21, 2017, after the federal tax law changes were known.
- 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.
- Sensitivity analysis shows substantial benefits of the Combined Projects persist when paired with PacifiCorp's wind repowering project and are not displaced when considering the potential procurement of solar PPA bids submitted into the on-going RFP for solar resources, the 2017S RFP.

Table 2-SD Updated SO Model and PaR PVRR(d)
(Benefit)/Cost of the Combined Projects ($ million)

Price-Policy Scenario	SO Model PVRR(d)	PaR Stochastic Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Low Gas, Zero CO2	($145)	($~~104~~126)	($~~109~~131)
Low Gas, Medium CO2	($186)	($~~124~~146)	($~~131~~152)
Low Gas, High CO2	($297)	($~~258~~280)	($~~272~~294)
Medium Gas, Zero CO2	($306)	($~~246~~268)	($~~258~~280)
Medium Gas, Medium CO2	($343)	($~~311~~333)	($~~327~~349)
Medium Gas, High CO2	($430)	($~~388~~409)	($~~406~~428)
High Gas, Zero CO2	($619)	($~~509~~531)	($~~535~~557)
High Gas, Medium CO2	($636)	($~~539~~561)	($~~567~~588)
High Gas, High CO2	($696)	($~~605~~627)	($~~636~~658)

Over a 20-year period, the Combined Projects reduce customer costs in all nine price-policy scenarios. This outcome is consistent in both the SO model and PaR results. Under the central price-policy scenario, assuming medium natural-gas prices and medium CO_2 prices, the PVRR(d) net benefits range between $~~311~~ 333 million, when derived from PaR stochastic-mean results, and $~~343~~ 349 million, when derived from ~~SO model~~PaR risk-adjusted results.

Q. What trends do you observe in the modeling results across the different price-policy scenarios?

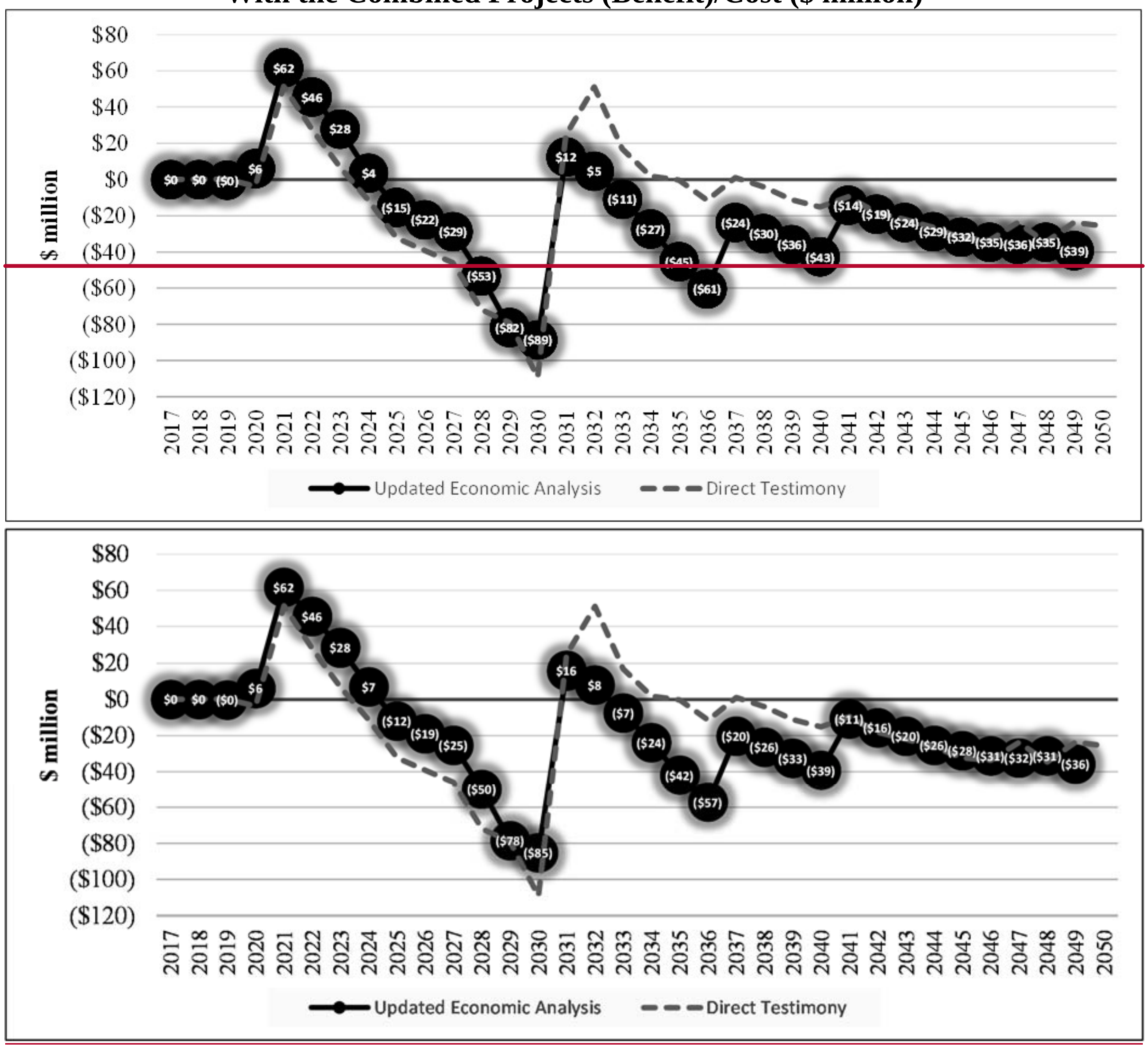
A. Projected system net benefits increase with higher natural-gas price assumptions, and similarly, increase with higher CO_2 price assumptions. Conversely, system net benefits decline when low natural-gas prices and low CO_2 prices are assumed. This trend holds annual data over the period 2017 through 2050 that was used to calculate the PVRR(d) results shown in the table are provided as Exhibit RMP__(RTL-5SD).

Table 3-SD. Updated Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of the Combined Projects ($ million)

Price-Policy Scenario	Annual Revenue Requirement PVRR(d)
Low Gas, Zero CO2	$~~169~~195
Low Gas, Medium CO2	$~~133~~159
Low Gas, High CO2	($~~105~~79)
Medium Gas, Zero CO2	($~~60~~34)
Medium Gas, Medium CO2	($~~177~~151)
Medium Gas, High CO2	($~~301~~275)
High Gas, Zero CO2	($~~437~~411)
High Gas, Medium CO2	($~~479~~453)
High Gas, High CO2	($~~585~~559)

When system costs and benefits from the Combined Projects are extended out through 2050, covering the full depreciable life of the owned wind projects included in the 2017R RFP final shortlist, the Combined Projects reduce customer costs in seven out of nine price-policy scenarios. Customer benefits range from $~~60~~ 34 million in the medium natural-gas, zero CO_2 scenario, to $~~585~~ 559 million in the high natural-gas, high CO_2 scenario. Under the central price-policy scenario, assuming medium natural-gas prices and medium CO_2 prices, the PVRR(d) benefits of the Combined Projects are $~~177~~ 151 million. The Combined Projects provide significant customer benefits in all price-policy scenarios, and the net benefits are unfavorable only when low natural-gas revenue requirement shown in the figure reflects updated costs, including capital revenue requirement (*i.e.*, depreciation, return, income taxes, and property taxes), O&M expenses, the Wyoming wind-production tax, and PTCs. The project costs are netted against updated system impacts from the Combined Projects, reflecting the change in NPC, emissions, non-NPC variable costs, and system fixed costs that are affected by, but not directly associated with, the Combined Projects.

Figure 5-SD Updated Total-System Annual Revenue Requirement With the Combined Projects (Benefit)/Cost ($ million)



The data shown in this figure for the updated economic analysis have the same basic profile as the data from the original economic analysis summarized in my direct

MW and 1,315 MW of solar PPA bids, from new projects all located in Utah, are added to the system by the SO model.

Q. What were the results of the solar sensitivity where solar PPA bids are assumed to be pursued in lieu of the Combined Projects?

A. Table 4-SD summarizes PVRR(d) results for the solar sensitivity where solar PPA bids are assumed to be pursued without any investments in the Combined Projects. This sensitivity was developed using SO model and PaR simulations through 2036 for the medium natural gas, medium CO_2 and the low natural gas, zero CO_2 price-policy scenarios. The results are shown alongside the benchmark study in which the Combined Projects were evaluated without solar PPA bids.

Table 4-SD Solar Sensitivity with Solar PPAs Included in lieu of the Combined Projects (Benefit)/Cost ($ million)

	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
Medium Gas, Medium CO2			
SO Model	($334)	($343)	$9
PaR Stochastic Mean	($~~203~~222)	($~~311~~333)	$~~108~~111
PaR Risk Adjusted	($~~213~~233)	($~~327~~349)	$~~114~~116
Low Gas, Zero CO2			
SO Model	($206)	($145)	($61)
PaR Stochastic Mean	($~~126~~141)	($~~104~~126)	($~~22~~15)
PaR Risk Adjusted	($~~133~~148)	($~~109~~131)	($~~24~~17)

In the medium natural gas, medium CO_2 price-policy scenario, a portfolio with the Combined Projects delivers greater customer benefits relative to a portfolio that adds solar PPA bids without the Combined Projects. Customer benefits are greater when the resource portfolio includes the Combined Projects without solar PPA bids by $~~114~~ 116 million in the medium natural gas, medium CO_2 price-policy scenario based on the risk-adjusted PaR results. In the low natural gas, zero CO_2 price-policy scenario, the portfolio with solar PPA bids and without the Combined Projects has higher net customer benefits relative to a portfolio containing just the Combined Projects. The increase in net benefits in the solar PPA portfolio is $~~24~~ 17 million based on the risk-adjusted PaR results.

Q. What were the results of the solar sensitivity where solar PPA bids are pursued with the Combined Projects?

A. Table 5-SD summarizes PVRR(d) results for the solar sensitivity where solar PPA bids are assumed to be pursued along with the proposed investments in the Combined Projects. This sensitivity was developed using SO model and PaR simulations through 2036 for the medium natural gas, medium CO_2 and the low natural gas, zero CO_2 price-policy scenarios. The results are shown alongside the benchmark study in which the Combined Projects were evaluated without solar PPA bids.

Table 5-SD Solar Sensitivity with Solar PPAs Included With the Combined Projects (Benefit)/Cost ($ million)

	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
Medium Gas, Medium CO2			
SO Model	($602)	($343)	($259)
PaR Stochastic Mean	($~~442~~482)	($~~311~~333)	($~~131~~149)
PaR Risk Adjusted	($~~464~~504)	($~~327~~349)	($~~137~~155)
Low Gas, Zero CO2			
SO Model	($286)	($145)	($141)
PaR Stochastic Mean	($~~185~~217)	($~~104~~126)	($~~81~~91)
PaR Risk Adjusted	($~~195~~227)	($~~109~~131)	($~~86~~96)

When the solar PPAs are pursued in addition to the Combined Projects, the total benefits increase, but are diluted (*i.e.*, the aggregate net benefits are less than the sum of the benefits for the cases where Combined Projects or solar PPAs are pursued independently).

Q. What conclusions can you draw from these solar sensitivity analyses?

A. These sensitivities demonstrate that should the company choose to pursue solar bids through the 2017S RFP, the resulting solar PPAs would not displace the Combined Projects as an alternative means to deliver economic savings for customers.

While the sensitivity with a portfolio containing solar PPAs without the Combined Projects produces a PVRR(d) with net benefits that are slightly higher than a portfolio without the solar PPAs in the low natural-gas, zero CO_2 price-policy scenario, both portfolios deliver customer benefits. 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. Importantly, the sensitivity that evaluates the Combined Projects with the solar PPAs

	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
Medium Gas, Medium CO2			
SO Model	($541)	($343)	($198)
PaR Stochastic Mean	($~~475~~497)	($~~311~~333)	($164)
PaR Risk Adjusted	($~~498~~520)	($~~327~~349)	($171)
Low Gas, Zero CO2			
SO Model	($313)	($145)	($169)
PaR Stochastic Mean	($~~255~~277)	($~~104~~126)	($152)
PaR Risk Adjusted	($~~268~~290)	($~~109~~131)	($159)

In the wind-repowering sensitivity, customer benefits increase significantly when the wind repowering project is implemented with the Combined Projects in both the medium natural-gas, medium CO_2, and the low natural-gas, zero CO_2 price-policy scenarios. These results demonstrate that customer benefits not only persist, but also increase, if both the wind-repowering project and the Combined Projects are completed.

REBUTTAL TESTIMONYRESOURCE NEED

Q. Dr. Zenger, Mr. Vastag, and Mr. Mullins argue that the Combined Projects are not tied to a specific resource need. (Zenger Direct, pages 9-11; Vastag Direct lines 53-64; Mullins Direct, page 10, lines 17-20.) Do you agree?

A. No. The Combined Projects meet both near-term and long-term resource needs identified in the company's 2017 IRP. The Combined Projects leverage federal PTCs to provide least-cost resources that meet these needs, and do so with substantial savings to customers.

Q. How does the company develop its forecast of resource need?

from the above forecast, then the above analysis could be invalidated by the additional information." *Id.* at 330-332. In this case, however, there is no additional information indicating that the longer-term future is likely to be different from the OFPC and therefore, according to the DPU's prior analysis, the "best approach" is to act today based on the OFPC.

Q. How does the company use each of the price-policy scenarios in its analysis?

A. The price-policy scenario assuming medium natural-gas prices and medium CO_2 prices represents the central forecast, around which the impact of lower or higher price assumptions can be evaluated. In the company's updated economic analysis, the PVRR(d) net benefit of the Combined Projects derived from the central price-policy scenario is $~~177~~ 151 million when calculated from projected nominal system costs through 2050. This outcome indicates that, when central price-policy assumptions are used, there is a reasonably sized cushion in the PVRR(d) results allowing for some erosion of the favorable economics should long-term natural-gas prices and CO_2 prices end up lower than what is assumed in this scenario. The other price-policy scenarios are useful in quantifying how sensitive the PVRR(d) results are to these key assumptions and provide a foundation for judging risk. Importantly, however, the company's updated analysis now shows robust customer benefits in nearly all price-policy scenarios without even accounting for potential upside benefits not reflected in the economic analysis.

Q. Mr. Peaco compares the company's natural-gas price forecasts with NYMEX Henry Hub natural-gas futures through 2029 as of November 28, 2017, and

Q. Mr. Peaco claims that the expected customer benefits are modest relative to the overall project costs and that there is very little certainty that customers will see significant, if any, cost savings. (Peaco Direct, line 316-318.) Mr. Hayet criticizes the Combined Projects because, under most scenarios, he claims they present modest benefits relative to the company's total revenue requirement. (Hayet Direct, lines 284-297.) Please respond.

A. First, Mr. Peaco mischaracterizes the relationship between the cost and benefits of the Combined Projects by comparing the up-front investment cost to the *net* benefits of the project. This artificially makes it appear that customer benefits are relatively small in relation to the investment required to deliver those benefits, when in fact, the gross benefits from the projects are actually greater than total project costs.

For instance, in the updated economic analysis, the PVRR(d) results calculated from the change in system costs through 2050 assuming medium natural-gas and medium CO_2 prices show a $~~177~~ 151 million *net* customer benefit from the Combined Projects. This is based on present-value project costs, including changes to run-rate operating costs, totaling $~~1.47~~1.50 billion. The present value of customer benefits, including federal PTC benefits, for this price-policy scenario is $1.65 billion, which is $~~177~~ 151 million greater than the present value of project costs. In fact, the present value of customer benefits among all nine price-policy scenarios ranges between $1.30 billion and $2.06 billion. In nearly all scenarios, the present value of customer benefits exceed the present value of customer costs.

Second, the fact the total expected benefits are small relative to the company's total revenue requirement means little in this case. It is hard to imagine a resource

Corrected Second Supplemental Direct Testimony

Rick T. Link

The updated results of the 2017R RFP and the extensive modeling that supports it continue to confirm that the Combined Projects are the least-cost, least-risk path available to serve the company's customers by meeting both near-term and long-term needs for additional resources. My second supplemental direct testimony explains the following:

- The Combined Projects continue to provide net customer benefits under all scenarios studied through 2036, and in seven of the nine scenarios through 2050.
- Customer benefits increase to $167 million in the medium case through 2050 (as compared to $151 million in the supplemental direct filing), and range from $357 million to $405 million in the medium case through 2036.
- The analysis reflects consideration of an interconnection-restudy process, that: 1) eliminated certain bids, including the company's McFadden Ridge II benchmark bid, from consideration in the 2017R RFP; and 2) supported an increase to the assumed level of interconnection capacity in the constrained area of PacifiCorp's system in eastern Wyoming.
- Sensitivity analysis continues to show substantial benefits of the Combined Projects persist when paired with PacifiCorp's wind repowering project and are not displaced or reduced when considering the potential procurement of solar PPA bids, updated with best-and-final pricing, submitted into the on-going RFP for solar resources, the 2017S RFP.

Table 2-SS Updated SO Model and PaR PVRR(d) (Benefit)/Cost of the Combined Projects ($ million)

Price-Policy Scenario	Second Supplemental Direct (Updated Final Shortlist)			Supplemental Direct (Original Final Shortlist)		
	SO Model PVRR(d)	PaR Stochastic Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)	SO Model PVRR(d)	PaR Stochastic Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Low Gas, Zero CO_2	($185)	($150)	($156)	($145)	($126)	($131)
Low Gas, Medium CO_2	($208)	($179)	($188)	($186)	($146)	($152)
Low Gas, High CO_2	($370)	($337)	($355)	($297)	($280)	($294)
Medium Gas, Zero CO_2	($377)	($319)	($334)	($306)	($268)	($280)
Medium Gas, Medium CO_2	($405)	($357)	($386)	($343)	($333)	($349)
Medium Gas, High CO_2	($489)	$(448)	($469)	($430)	($409)	($428)
High Gas, Zero CO_2	($699)	($568)	($596)	($619)	($531)	($557)
High Gas, Medium CO_2	($716)	($603)	($633)	($636)	($561)	($588)
High Gas, High CO_2	($781)	($694)	($728)	($696)	($627)	($658)

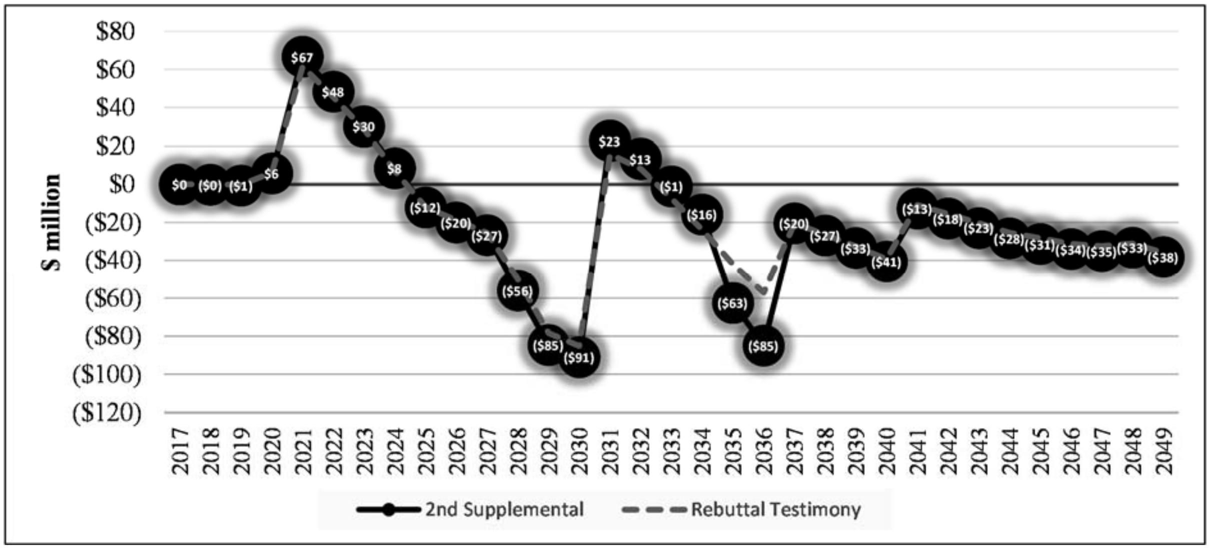
Over a 20-year period, the Combined Projects reduce customer costs in all nine price-policy scenarios. This outcome is consistent in both the SO model and PaR results. Under the central price-policy scenario, when applying medium natural gas, medium CO_2 price-policy assumptions, the PVRR(d) net benefits range between $357 million (up from $333 million), when derived from PaR stochastic-mean results, and $405 million (up from $343 million), when derived from SO model results. Net benefits increase relative to those shown in my supplemental direct testimony. This is driven by the increased interconnection capacity associated with the Aeolus-to-Bridger/Anticline transmission line, which enables selection of the Ekola Flats benchmark resource. Without this update, there was not sufficient interconnection capacity to accommodate the Ekola Flats benchmark with the TB Flats I & II and Cedar Springs bids.

Table 3-SS. Updated Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of the Combined Projects ($ million)

Price-Policy Scenario	Second Supplemental Direct (Updated Final Shortlist)	Supplemental Direct (Original Final Shortlist)
Low Gas, Zero CO_2	$184	$195
Low Gas, Medium CO_2	$127	$159
Low Gas, High CO_2	($147)	($79)
Medium Gas, Zero CO_2	($92)	($34)
Medium Gas, Medium CO_2	($167)	($151)
Medium Gas, High CO_2	($304)	($275)
High Gas, Zero CO_2	($448)	($411)
High Gas, Medium CO_2	($499)	($453)
High Gas, High CO_2	($635)	($559)

When system costs and benefits from the Combined Projects are extended out through 2050, covering the full depreciable life of the owned-wind projects included in the updated 2017R RFP final shortlist, the Combined Projects reduce customer costs in seven out of nine price-policy scenarios. Customer net benefits range from $92 million in the medium natural-gas, zero CO_2 price-policy scenario (up from $34 million) to $635 million in the high natural gas, high CO_2 price-policy scenario (up from $559 million). Under the central price-policy scenario, when applying medium natural gas, medium CO_2 price-policy assumptions, the PVRR(d) benefits of the Combined Projects are $167 million (up from $151 million). The Combined Projects provide significant customer benefits in all price-policy scenarios, and the net benefits are unfavorable only when low natural-gas prices are paired with zero or medium CO_2 prices. These results continue to show that upside benefits far outweigh downside risks.

Figure 1-SS Updated Total-System Annual Revenue Requirement
With the Combined Projects (Benefit)/Cost ($ million)



The data shown in this figure for the updated economic analysis have the same basic profile as the data from the economic analysis summarized in my supplemental direct testimony. Despite a reduction in PTC benefits associated with changes in federal tax law, the reduced costs from winning bids from the 2017R RFP continue to generate substantial near-term customer benefits and continue to contribute to customer benefits over the long term. The Combined Projects produce net benefits in 23 years out of the 30 years that the proposed owned-wind resources selected to the 2017R RFP final shortlist are assumed to operate.

As noted in my supplemental direct testimony, the year-on-year reduction in net benefits from 2036 to 2037 is driven by the company's conservative approach to extrapolate benefits from 2037 through 2050 based on modeled results from the 2028-through-2036 time frame. This leads to an abrupt reduction in the benefits in 2037, and a subsequent year-on-year reduction to net benefits, which breaks from the trend observed in the model results over the 2035-to-2036 time frame. This extrapolation

Table 4-SS Updated Solar Sensitivity with Solar PPAs Included in lieu of the Combined Projects (Benefit)/Cost ($ million)

	Sensitivity	Benchmark	Change in
Medium Gas, Medium CO2			
SO Model	($343)	($405)	$61
PaR Stochastic Mean	($228)	($357)	$129
PaR Risk Adjusted	($237)	($386)	$149
Low Gas, Zero CO2			
SO Model	($196)	($185)	($11)
PaR Stochastic Mean	($139)	($150)	$11
PaR Risk Adjusted	($145)	($156)	$11

In this sensitivity, the SO model selects 1,122 MW of solar PPA bids in the low natural gas, zero CO_2 price-policy scenario and 1,419 MW of solar PPA bids in the medium natural gas, medium CO_2 price-policy scenario. All of the selected solar PPA bids are for projects located in Utah.

In the medium natural gas, medium CO_2 price-policy scenario, a portfolio with the Combined Projects delivers greater customer benefits relative to a portfolio that adds solar PPA bids without the Combined Projects. Customer benefits are greater when the resource portfolio includes the Combined Projects without solar PPA bids by $149 million in the medium natural gas, medium CO_2 price-policy scenario based on the risk-adjusted PaR results. In the low natural gas, zero CO_2 price-policy scenario, the portfolio with the Combined Projects delivers slightly greater customer benefits relative to a portfolio that adds solar PPA bids without the Combined Projects when modeled in PaR, and slightly lower customer benefits when analyzed with the SO model. The decrease in net benefits in the solar PPA portfolio is $11 million based on the risk-adjusted PaR results.

When analyzed without the Combined Projects, the solar PPA bids produce net customer benefits that are lower than the benefits expected from the Combined Projects in the medium natural gas, medium CO_2 price-policy scenario. While the sensitivity with a portfolio containing solar PPAs without the Combined Projects produces PVRR(d) results that are similar to the PVRR(d) results with only the Combined Projects in the low natural-gas, zero CO_2 price-policy scenario, both portfolios deliver customer benefits. 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.

Q. What were the results of the solar sensitivity where solar PPA bids are pursued with the Combined Projects?

A. Table 5-SS summarizes PVRR(d) results for the solar sensitivity where solar PPA bids are assumed to be pursued along with the proposed investments in the Combined Projects. This sensitivity was developed using SO model and PaR simulations through 2036 for the medium natural gas, medium CO_2 and the low natural gas, zero CO_2 price-policy scenarios. The results are shown alongside the benchmark study in which the Combined Projects were evaluated without solar PPA bids.

Table 5-SS Updated Solar Sensitivity with Solar PPAs Included With the Combined Projects (Benefit)/Cost ($ million)

	Sensitivity	Benchmark	Change in
Medium Gas, Medium CO2			
SO Model	($647)	($405)	($242)
PaR Stochastic Mean	($519)	($357)	($163)
PaR Risk Adjusted	($543)	($386)	($157)
Low Gas, Zero CO2			
SO Model	($312)	($185)	($127)
PaR Stochastic Mean	($250)	($150)	($100)
PaR Risk Adjusted	($259)	($156)	($103)

and to reflect the most recent cost-and performance estimates for the wind repowering project as described in my supplemental direct testimony filed in Docket No. 17-035-39.

Q. What were the results of the updated wind-repowering sensitivity?

A. Table 6-SS summarizes PVRR(d) results for this wind-repowering sensitivity. This sensitivity was developed using SO model and PaR simulations through 2036 for the medium natural-gas, medium CO_2 and the low natural-gas, zero CO_2 price-policy scenarios. The results are shown alongside the benchmark study in which the Combined Projects were evaluated without wind repowering.

**Table 6-SS Wind-Repowering
Sensitivity (Benefit)/Cost ($ million)**

	Sensitivity	Benchmark	Change in
Medium Gas, Medium CO2			
SO Model	($608)	($405)	($204)
PaR Stochastic Mean	($541)	($357)	($184)
PaR Risk Adjusted	($567)	($386)	($181)
Low Gas, Zero CO2			
SO Model	($334)	($185)	($149)
PaR Stochastic Mean	($281)	($150)	($131)
PaR Risk Adjusted	($295)	($156)	($138)

In the updated wind-repowering sensitivity, customer benefits increase significantly when the wind repowering project is implemented with the Combined Projects in both the medium natural-gas, medium CO_2, and the low natural-gas, zero CO_2 price-policy scenarios. These results continue to demonstrate that customer benefits not only persist, but also increase, if both the wind-repowering project and the Combined Projects are completed.

The updated results of the 2017R RFP and the extensive modeling that supports it continue to confirm that the Combined Projects are the least-cost, least-risk path available to serve the company's customers by meeting both near-term and long-term needs for additional resources. My second supplemental direct testimony explains the following:

- The Combined Projects continue to provide net customer benefits under all scenarios studied through 2036, and in seven of the nine scenarios through 2050.
- Customer benefits increase to $~~196~~ 167 million in the medium case through 2050 (as compared to $~~177~~ 151 million in the supplemental direct filing), and range from $~~333~~ 357 million to $405 million in the medium case through 2036.
- The analysis reflects consideration of an interconnection-restudy process, that: 1) eliminated certain bids, including the company's McFadden Ridge II benchmark bid, from consideration in the 2017R RFP; and 2) supported an increase to the assumed level of interconnection capacity in the constrained area of PacifiCorp's system in eastern Wyoming.
- Sensitivity analysis continues to show substantial benefits of the Combined Projects persist when paired with PacifiCorp's wind repowering project and are not displaced or reduced when considering the potential procurement of solar PPA bids, updated with best-and-final pricing, submitted into the on-going RFP for solar resources, the 2017S RFP.

Table 2-SS Updated SO Model and PaR PVRR(d) (Benefit)/Cost of the Combined Projects ($ million)

Price-Policy Scenario	Second Supplemental Direct (Updated Final Shortlist)			Supplemental Direct (Original Final Shortlist)		
	SO Model PVRR(d)	PaR Stochastic Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)	SO Model PVRR(d)	PaR Stochastic Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Low Gas, Zero CO_2	($185)	($~~126~~150)	($~~132~~156)	($145)	($~~104~~126)	($~~109~~131)
Low Gas, Medium CO_2	($208)	($~~155~~179)	($~~164~~188)	($186)	($~~124~~146)	($~~131~~152)
Low Gas, High CO_2	($370)	($~~313~~337)	($~~331~~355)	($297)	($~~258~~280)	($~~272~~294)
Medium Gas, Zero CO_2	($377)	($~~295~~319)	($~~310~~334)	($306)	($~~246~~268)	($~~258~~280)
Medium Gas, Medium CO_2	($405)	($~~333~~357)	($~~362~~386)	($343)	($~~311~~333)	($~~327~~349)
Medium Gas, High CO_2	($489)	$(~~424~~448)	($~~445~~469)	($430)	($~~388~~409)	($~~406~~428)
High Gas, Zero CO_2	($699)	($~~545~~568)	($~~572~~596)	($619)	($~~509~~531)	($~~535~~557)
High Gas, Medium CO_2	($716)	($~~579~~603)	($~~609~~633)	($636)	($~~539~~561)	($~~567~~588)
High Gas, High CO_2	($781)	($~~671~~694)	($~~705~~728)	($696)	($~~605~~627)	($~~636~~658)

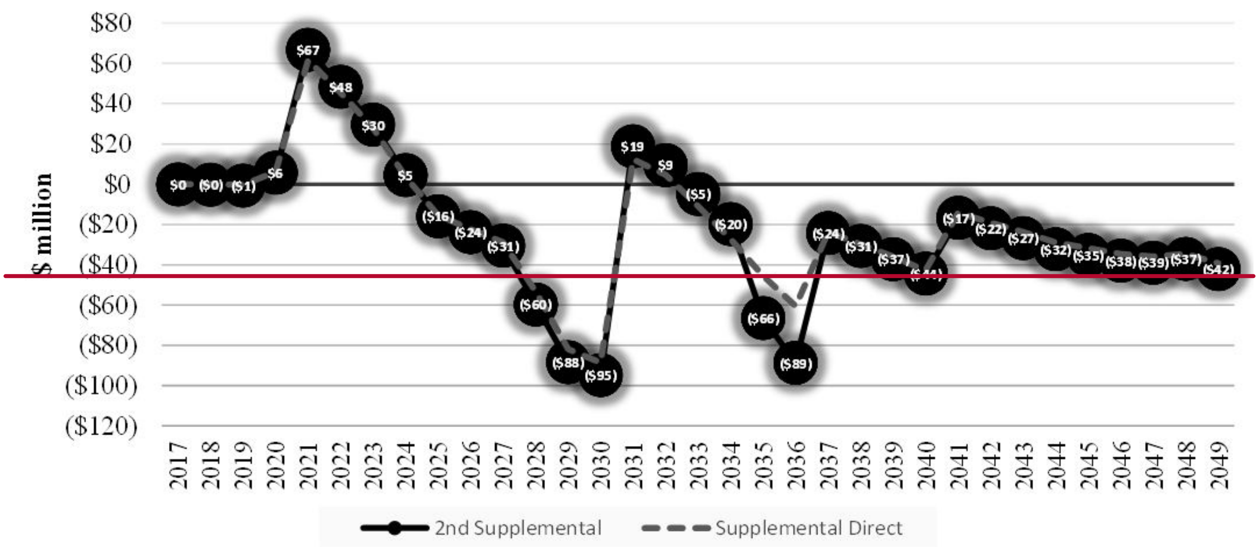
Over a 20-year period, the Combined Projects reduce customer costs in all nine price-policy scenarios. This outcome is consistent in both the SO model and PaR results. Under the central price-policy scenario, when applying medium natural gas, medium CO_2 price-policy assumptions, the PVRR(d) net benefits range between $~~333~~ 357 million (up from $~~311~~ 333 million), when derived from PaR stochastic-mean results, and $405 million (up from $343 million), when derived from SO model results. Net benefits increase relative to those shown in my supplemental direct testimony. This is driven by the increased interconnection capacity associated with the Aeolus-to-Bridger/Anticline transmission line, which enables selection of the Ekola Flats benchmark resource. Without this update, there was not sufficient interconnection

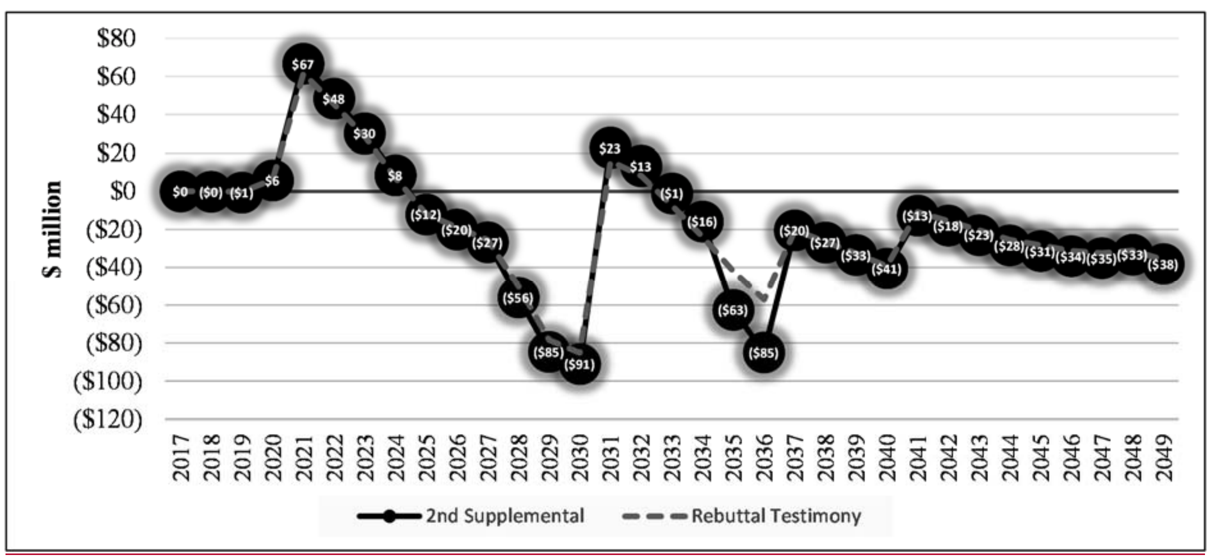
Table 3-SS. Updated Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of the Combined Projects ($ million)

Price-Policy Scenario	Second Supplemental Direct (Updated Final Shortlist)	Supplemental Direct (Original Final Shortlist)
Low Gas, Zero CO_2	$~~155~~184	$~~169~~195
Low Gas, Medium CO_2	$~~98~~127	$~~133~~159
Low Gas, High CO_2	($~~176~~147)	($~~105~~79)
Medium Gas, Zero CO_2	($~~121~~92)	($~~60~~34)
Medium Gas, Medium CO_2	($~~196~~167)	($~~177~~151)
Medium Gas, High CO_2	($~~333~~304)	($~~301~~275)
High Gas, Zero CO_2	($~~477~~448)	($~~437~~411)
High Gas, Medium CO_2	($~~528~~499)	($~~479~~453)
High Gas, High CO_2	($~~664~~635)	($~~585~~559)

When system costs and benefits from the Combined Projects are extended out through 2050, covering the full depreciable life of the owned-wind projects included in the updated 2017R RFP final shortlist, the Combined Projects reduce customer costs in seven out of nine price-policy scenarios. Customer net benefits range from $~~121~~ 92 million in the medium natural-gas, zero CO_2 price-policy scenario (up from $~~60~~ 34 million) to $~~664~~ 635 million in the high natural gas, high CO_2 price-policy scenario (up from $~~585~~ 559 million). Under the central price-policy scenario, when applying medium natural gas, medium CO_2 price-policy assumptions, the PVRR(d) benefits of the Combined Projects are $~~196~~ 167 million (up from $~~177~~ 151 million). The Combined Projects provide significant customer benefits in all price-policy scenarios, and the net benefits are unfavorable only when low natural-gas prices are paired with

Figure 1-SS Updated Total-System Annual Revenue Requirement With the Combined Projects (Benefit)/Cost ($ million)





The data shown in this figure for the updated economic analysis have the same basic profile as the data from the economic analysis summarized in my supplemental direct testimony. Despite a reduction in PTC benefits associated with changes in federal tax law, the reduced costs from winning bids from the 2017R RFP continue to generate substantial near-term customer benefits and continue to contribute to customer benefits over the long term. The Combined Projects produce net benefits in 23 years out of the

A. Table 4-SS summarizes PVRR(d) results for the solar sensitivity where solar PPA bids are assumed to be pursued without any investments in the Combined Projects. This sensitivity was developed using SO model and PaR simulations through 2036 for the medium natural gas, medium CO_2 and the low natural gas, zero CO_2 price-policy scenarios. The results are shown alongside the benchmark study in which the Combined Projects were evaluated without solar PPA bids.

Table 4-SS Updated Solar Sensitivity with Solar PPAs Included in lieu of the Combined Projects (Benefit)/Cost ($ million)

	Sensitivity	Benchmark	Change in
Medium Gas, Medium CO2			
SO Model	($343)	($405)	$61
PaR Stochastic Mean	($~~206~~228)	($~~333~~357)	$~~127~~129
PaR Risk Adjusted	($~~216~~237)	($~~362~~386)	$~~146~~149
Low Gas, Zero CO2			
SO Model	($196)	($185)	($11)
PaR Stochastic Mean	($~~123~~139)	($~~126~~150)	$~~3~~11
PaR Risk Adjusted	($~~130~~145)	($~~132~~156)	$~~3~~11

In this sensitivity, the SO model selects 1,122 MW of solar PPA bids in the low natural gas, zero CO_2 price-policy scenario and 1,419 MW of solar PPA bids in the medium natural gas, medium CO_2 price-policy scenario. All of the selected solar PPA bids are for projects located in Utah.

In the medium natural gas, medium CO_2 price-policy scenario, a portfolio with the Combined Projects delivers greater customer benefits relative to a portfolio that adds solar PPA bids without the Combined Projects. Customer benefits are greater when the resource portfolio includes the Combined Projects without solar PPA bids by $~~146~~ 149 million in the medium natural gas, medium CO_2 price-policy scenario based on the risk-adjusted PaR results. In the low natural gas, zero CO_2 price-policy scenario, the portfolio with the Combined Projects delivers slightly greater customer benefits relative to a portfolio that adds solar PPA bids without the Combined Projects when modeled in PaR, and slightly lower customer benefits when analyzed with the SO model. The decrease in net benefits in the solar PPA portfolio is $~~3~~ 11 million based on the risk-adjusted PaR results.

When analyzed without the Combined Projects, the solar PPA bids produce net customer benefits that are lower than the benefits expected from the Combined Projects in the medium natural gas, medium CO_2 price-policy scenario. While the sensitivity with a portfolio containing solar PPAs without the Combined Projects produces PVRR(d) results that are similar to the PVRR(d) results with only the Combined Projects in the low natural-gas, zero CO_2 price-policy scenario, both portfolios deliver customer benefits. 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.

Q. What were the results of the solar sensitivity where solar PPA bids are pursued with the Combined Projects?

A. Table 5-SS summarizes PVRR(d) results for the solar sensitivity where solar PPA bids are assumed to be pursued along with the proposed investments in the Combined Projects. This sensitivity was developed using SO model and PaR simulations through 2036 for the medium natural gas, medium CO_2 and the low natural gas, zero CO_2 price-policy scenarios. The results are shown alongside the benchmark study in which the Combined Projects were evaluated without solar PPA bids.

Table 5-SS Updated Solar Sensitivity with Solar PPAs Included With the Combined Projects (Benefit)/Cost ($ million)

	Sensitivity	Benchmark	Change in
Medium Gas, Medium CO2			
SO Model	($647)	($405)	($242)
PaR Stochastic Mean	($~~455~~519)	($~~333~~357)	($~~122~~163)
PaR Risk Adjusted	($~~479~~543)	($~~362~~386)	($~~116~~157)
Low Gas, Zero CO2			
SO Model	($312)	($185)	($127)
PaR Stochastic Mean	($~~197~~250)	($~~126~~150)	($~~71~~100)
PaR Risk Adjusted	($~~206~~259)	($~~132~~156)	($~~74~~103)

In this sensitivity, the SO model continues to choose the winning bids included in the updated 2017R RFP final shortlist as part of the least-cost bid portfolio. In addition to these wind resource selections, the SO model selects 1,042 MW of solar PPA bids in the low natural gas, zero CO_2 price-policy scenario and 1,419 MW of solar PPA bids in the medium natural gas, medium CO_2 price-policy scenario. Again, all of the selected solar PPA bids are for projects located in Utah.

When the solar PPAs are assumed to be pursued in addition to the Combined Projects, total net customer benefits increase. This result is consistent with the company's expectation expressed during the 2017R RFP approval process in Docket No. 17-035-23 that cost-effective solar opportunities would not displace the Combined Projects, but would only potentially add to incremental resource procurement opportunities that might provide net customer benefits. Importantly, this sensitivity produces net benefits that are greater than the net benefits from the Combined Projects without the solar PPAs. This confirms that near-term renewable procurement is not a matter of whether the company should pursue the Combined Projects *or* the solar PPAs, but whether the company should consider both opportunities. At this time, it is clear that the Combined Projects provide significant net benefits, and that these benefits are not eliminated if the company were to also pursue solar PPA bids through the 2017S RFP.

WIND-REPOWERING SENSITIVITY

Q. Has the company updated its sensitivity analysis related to the wind repowering project?

A. Yes. The wind repowering sensitivity was updated to reflect the updated final shortlist and to reflect the most recent cost-and performance estimates for the wind repowering project as described in my supplemental direct testimony filed in Docket No. 17-035-39.

Q. What were the results of the updated wind-repowering sensitivity?

A. Table 6-SS summarizes PVRR(d) results for this wind-repowering sensitivity. This sensitivity was developed using SO model and PaR simulations through 2036 for the medium natural-gas, medium CO_2 and the low natural-gas, zero CO_2 price-policy scenarios. The results are shown alongside the benchmark study in which the Combined Projects were evaluated without wind repowering.

Table 6-SS Wind-Repowering Sensitivity (Benefit)/Cost ($ million)

	Sensitivity	Benchmark	Change in
Medium Gas, Medium CO2			
SO Model	($608)	($405)	($204)
PaR Stochastic Mean	($~~517~~541)	($~~333~~357)	($184)
PaR Risk Adjusted	($~~543~~567)	($~~362~~386)	($181)
Low Gas, Zero CO2			
SO Model	($334)	($185)	($149)
PaR Stochastic Mean	($~~257~~281)	($~~126~~150)	($131)
PaR Risk Adjusted	($~~271~~295)	($~~132~~156)	($138)

Rocky Mountain Power
Corrected Exhibit RMP___(RTL-4SD)
Docket No. 17-035-40
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

CORRECTED
Exhibit Accompanying Supplemental Testimony of Rick T. Link

SO Model and PaR Model Annual Results ($ million)

February 2018

SO Model Annual Results ($ million)

Low Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$806	$0	$0	$0	$2	$58	$62	$62	$64	$68	$68	$72	$72	$77	$102	$221	$225	$230	$235	$241	$246
Change in NPC	($806)	($0)	$0	$1	($11)	($91)	($92)	($95)	($94)	($98)	($98)	($101)	($114)	($114)	($127)	($124)	($126)	($135)	($150)	($144)	($144)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in DSM	($64)	$0	($0)	($1)	($2)	($3)	($4)	($5)	($7)	($9)	($9)	($11)	($11)	($11)	($11)	($11)	($11)	($11)	($11)	($11)	($10)
Change in System Fixed Cost	($81)	$0	($0)	$0	($0)	($3)	($3)	($3)	($6)	($6)	($6)	($6)	($6)	($19)	($19)	($19)	($32)	($22)	($12)	($27)	($27)
Net (Benefit)/Cost	($145)	($0)	($0)	($0)	($12)	($39)	($37)	($42)	($44)	($45)	($46)	($46)	($59)	($67)	($54)	$67	$57	$62	$62	$59	$65

Low Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$806	$0	$0	$0	$2	$58	$62	$62	$64	$68	$68	$72	$72	$77	$102	$221	$225	$230	$235	$241	$246
Change in NPC	($795)	($0)	$0	$1	($11)	($91)	($92)	($95)	($95)	($99)	($98)	($101)	($114)	($113)	($126)	($123)	($127)	($129)	($135)	($139)	($134)
Change in Emissions	($16)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($3)	($8)	($8)	($8)	($7)	($7)	($9)
Change in DSM	($77)	$0	($0)	($1)	($3)	($4)	($5)	($5)	($8)	($8)	($9)	($10)	($10)	($12)	($12)	($14)	($16)	($17)	($18)	($19)	($20)
Change in System Fixed Cost	($103)	$0	($0)	($0)	($0)	($3)	($3)	($3)	($6)	($6)	($6)	($6)	($6)	($17)	($25)	($26)	($22)	($29)	($56)	($32)	($46)
Net (Benefit)/Cost	($186)	($0)	($0)	($1)	($12)	($39)	($37)	($42)	($45)	($44)	($46)	($46)	($59)	($66)	($65)	$49	$53	$46	$19	$44	$37

Low Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$806	$0	$0	$0	$2	$58	$62	$62	$64	$68	$68	$72	$72	$77	$102	$221	$225	$230	$235	$241	$246
Change in NPC	($851)	($0)	$0	$0	($13)	($93)	($94)	($97)	($98)	($102)	($105)	($113)	($135)	($142)	($143)	($131)	($129)	($148)	($157)	($131)	($118)
Change in Emissions	($136)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($10)	($18)	($16)	($21)	($36)	($52)	($57)	($44)	($44)	($41)	($56)
Change in DSM	($27)	$0	$0	($0)	($1)	($1)	($2)	($2)	($2)	($2)	($3)	($4)	($4)	($4)	($5)	($5)	($5)	($6)	($6)	($8)	($9)
Change in System Fixed Cost	($89)	$0	$0	$0	($0)	($3)	($3)	($3)	($6)	($6)	($6)	($6)	($6)	($20)	($21)	($21)	($20)	($24)	($17)	($41)	($42)
Net (Benefit)/Cost	($297)	($0)	$0	($0)	($12)	($38)	($37)	($41)	($43)	($43)	($56)	($68)	($89)	($111)	($102)	$13	$13	$9	$12	$19	$21

Medium Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$806	$0	$0	$0	$2	$58	$62	$62	$64	$68	$68	$72	$72	$77	$102	$221	$225	$230	$235	$241	$246
Change in NPC	($978)	($0)	$0	$1	($12)	($97)	($99)	($102)	($105)	($116)	($115)	($120)	($133)	($148)	($166)	($181)	($184)	($191)	($204)	($181)	($146)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in DSM	($43)	$0	($1)	($1)	($2)	($2)	($3)	($3)	($4)	($4)	($5)	($5)	($6)	($7)	($7)	($8)	($9)	($9)	($9)	($9)	($9)
Change in System Fixed Cost	($92)	$0	($0)	($0)	($0)	($3)	($3)	($3)	($6)	($6)	($6)	($6)	($6)	($20)	($20)	($20)	($17)	($22)	$11	($43)	($94)
Net (Benefit)/Cost	($306)	($0)	($0)	($0)	($12)	($44)	($44)	($47)	($52)	($58)	($59)	($59)	($74)	($98)	($91)	$12	$16	$9	$34	$8	($2)

Medium Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$806	$0	$0	$0	$2	$58	$62	$62	$64	$68	$68	$72	$72	$77	$102	$221	$225	$230	$235	$241	$246
Change in NPC	($906)	($0)	$0	$0	($13)	($97)	($100)	($102)	($106)	($117)	($115)	($119)	($133)	($149)	($170)	($187)	($190)	($175)	($160)	($87)	($8)
Change in Emissions	($10)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($5)	($3)	($5)	($5)	($5)	($4)	($2)
Change in DSM	($41)	$0	$0	($1)	($1)	($2)	($3)	($3)	($4)	($4)	($5)	($6)	($6)	($7)	($7)	($8)	($8)	($9)	($9)	($9)	($9)
Change in System Fixed Cost	($193)	$0	$0	$0	($0)	($3)	($3)	($3)	($6)	($6)	($6)	($6)	($6)	($19)	($19)	($19)	($17)	($44)	($69)	($151)	($247)
Net (Benefit)/Cost	($343)	($0)	$0	($0)	($12)	($44)	($44)	($47)	($53)	($59)	($59)	($59)	($74)	($98)	($100)	$2	$5	($2)	($8)	($10)	($19)

Medium Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$806	$0	$0	$0	$2	$58	$62	$62	$64	$68	$68	$72	$72	$77	$102	$221	$225	$230	$235	$241	$246
Change in NPC	($868)	($0)	$0	$1	($13)	($92)	($95)	($97)	($101)	($111)	($108)	($119)	($124)	($123)	($169)	($189)	($186)	($72)	($74)	($154)	($160)
Change in Emissions	($96)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($13)	($18)	($36)	($49)	($30)	($13)	($17)	($17)	($18)	($18)	($20)
Change in DSM	($48)	$0	($1)	($1)	($2)	($3)	($3)	($3)	($4)	($5)	($6)	($6)	($7)	($9)	($9)	($9)	($9)	($9)	($9)	($9)	($10)
Change in System Fixed Cost	($224)	$0	$0	$0	($0)	($9)	($9)	($10)	($13)	($13)	($13)	($14)	($14)	($25)	($25)	($26)	($27)	($147)	($148)	($73)	($75)
Net (Benefit)/Cost	($430)	($0)	($0)	($0)	($12)	($46)	($46)	($48)	($54)	($61)	($73)	($85)	($109)	($129)	($132)	($17)	($14)	($15)	($14)	($14)	($18)

High Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$806	$0	$0	$0	$2	$58	$62	$62	$64	$68	$68	$72	$72	$77	$102	$221	$225	$230	$235	$241	$246
Change in NPC	($1,067)	($0)	$0	$1	($19)	($117)	($126)	($118)	($128)	($136)	($135)	($140)	($156)	($172)	($163)	($150)	($94)	($180)	($153)	($242)	($230)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in DSM	($39)	$0	($1)	($1)	($2)	($2)	($2)	($3)	($5)	($5)	($5)	($5)	($6)	($6)	($6)	($6)	($7)	($7)	($8)	($8)	($9)
Change in System Fixed Cost	($319)	$0	$0	$0	($0)	($3)	($3)	($26)	($30)	($30)	($31)	($32)	($32)	($39)	($75)	($94)	($149)	($67)	($109)	($51)	($71)
Net (Benefit)/Cost	($619)	($0)	($0)	($0)	($19)	($64)	($69)	($86)	($99)	($103)	($103)	($105)	($123)	($141)	($142)	($30)	($25)	($24)	($34)	($60)	($64)

High Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$806	$0	$0	$0	$2	$58	$62	$62	$64	$68	$68	$72	$72	$77	$102	$221	$225	$230	$235	$241	$246
Change in NPC	($1,000)	($0)	$0	$1	($19)	($117)	($126)	($102)	($106)	($116)	($116)	($120)	($134)	($146)	($139)	($136)	($105)	($173)	($168)	($253)	($274)
Change in Emissions	($13)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($3)	($4)	($3)	($6)	($6)	($9)	($10)
Change in DSM	($42)	$0	($1)	($1)	($2)	($2)	($2)	($3)	($5)	($5)	($5)	($6)	($6)	($6)	($7)	($7)	($8)	($8)	($9)	($9)	($10)
Change in System Fixed Cost	($387)	$0	$0	$0	($0)	($3)	($3)	($47)	($51)	($52)	($53)	($54)	($55)	($62)	($95)	($108)	($141)	($71)	($84)	($35)	($28)
Net (Benefit)/Cost	($636)	($0)	($0)	($0)	($19)	($64)	($69)	($90)	($98)	($105)	($106)	($108)	($124)	($139)	($143)	($34)	($31)	($28)	($32)	($67)	($76)

High Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$806	$0	$0	$0	$2	$58	$62	$62	$64	$68	$68	$72	$72	$77	$102	$221	$225	$230	$235	$241	$246
Change in NPC	($1,046)	($0)	$0	$1	($19)	($115)	($124)	($87)	($90)	($99)	($99)	($102)	($116)	($131)	($149)	($203)	($203)	($191)	($232)	($298)	($311)
Change in Emissions	($64)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($4)	($8)	($11)	($15)	($18)	($10)	($22)	($19)	($26)	($28)	($28)
Change in DSM	($39)	$0	($1)	($1)	($1)	($1)	($1)	($3)	($4)	($4)	($4)	($5)	($6)	($6)	($6)	($7)	($7)	($8)	($8)	($9)	($10)
Change in System Fixed Cost	($352)	$0	$0	$0	($0)	($6)	($6)	($64)	($68)	($70)	($71)	($73)	($74)	($74)	($75)	($46)	($39)	($59)	($45)	$6	$4
Net (Benefit)/Cost	($696)	($0)	($0)	($0)	($19)	($65)	($70)	($93)	($100)	($105)	($111)	($116)	($135)	($149)	($146)	($45)	($46)	($46)	($76)	($89)	($100)

PaR Stochastic-Mean Results ($ million)

Low Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$784	$0	$0	$0	$2	$55	$59	$59	$61	$65	$65	$69	$69	$73	$99	$217	$222	$227	$232	$237	$242
Change in NPC	($733)	$0	$0	$1	($12)	($85)	($86)	($88)	($87)	($91)	($89)	($89)	($99)	($103)	($110)	($113)	($116)	($120)	($132)	($132)	($132)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in VOM	($17)	$0	$0	$0	($0)	($2)	($2)	($2)	($2)	($2)	($3)	($3)	($2)	($2)	($2)	($2)	($2)	($3)	($3)	($2)	($3)
Change in DSM	($71)	$0	($0)	($1)	($3)	($3)	($4)	($6)	($8)	($10)	($10)	($12)	($12)	($12)	($12)	($12)	($12)	($12)	($12)	($12)	($11)
Change in Deficiency	($8)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($3)	($4)	($3)	($3)	($6)	($2)	($4)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($80)	$0	($0)	$0	($0)	($3)	($3)	($3)	($6)	($6)	($6)	($6)	($6)	($18)	($19)	($19)	($32)	($22)	($12)	($27)	($27)
Net (Benefit)/Cost	($126)	$0	($0)	($1)	($13)	($38)	($36)	($41)	($43)	($44)	($43)	($40)	($51)	($63)	($47)	$67	$57	$67	$66	$61	$65

Low Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$784	$0	$0	$0	$2	$55	$59	$59	$61	$65	$65	$69	$69	$73	$99	$217	$222	$227	$232	$237	$242
Change in NPC	($717)	$0	$0	$1	($11)	($85)	($85)	($88)	($87)	($91)	($89)	($89)	($99)	($102)	($109)	($111)	($113)	($114)	($116)	($122)	($116)
Change in Emissions	($25)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($9)	($9)	($10)	($12)	($14)	($12)	($13)
Change in VOM	($26)	$0	$0	$0	($0)	($2)	($2)	($2)	($2)	($2)	($3)	($3)	($2)	($2)	($6)	($6)	($6)	($7)	($7)	($7)	($7)
Change in DSM	($85)	$0	($0)	($2)	($3)	($4)	($5)	($6)	($8)	($9)	($10)	($11)	($11)	($13)	($14)	($15)	($17)	($19)	($20)	($20)	($22)
Change in Deficiency	$26	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1)	$2	$13	$13	$18	$15	$13	$9
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($103)	$0	($0)	($0)	($0)	($3)	($3)	($3)	($6)	($6)	($6)	($6)	($6)	($17)	($25)	($26)	($22)	($29)	($56)	($32)	($46)
Net (Benefit)/Cost	($146)	$0	($0)	($1)	($13)	($38)	($36)	($41)	($43)	($43)	($43)	($40)	($51)	($62)	($62)	$62	$67	$65	$35	$56	$47

Low Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$784	$0	$0	$0	$2	$55	$59	$59	$61	$65	$65	$69	$69	$73	$99	$217	$222	$227	$232	$237	$242

Change in NPC	($775)	$0	$0	$0	($13)	($87)	($87)	($90)	($90)	($95)	($96)	($99)	($114)	($118)	($126)	($127)	($129)	($131)	($135)	($118)	($118)
Change in Emissions	($149)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($10)	($20)	($28)	($35)	($44)	($46)	($48)	($50)	($53)	($45)	($45)
Change in VOM	($16)	$0	$0	$0	($0)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($3)	($4)	($2)	($2)
Change in DSM	($30)	$0	$0	($0)	($1)	($1)	($2)	($2)	($3)	($3)	($4)	($4)	($4)	($5)	($5)	($5)	($6)	($6)	($6)	($9)	($10)
Change in Deficiency	($5)	$0	$0	($0)	$0	$0	$0	$0	$0	$0	$0	$0	($0)	($1)	($3)	($3)	($3)	($1)	($1)	($1)	($3)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($89)	$0	$0	$0	($0)	($3)	($3)	($3)	($6)	($6)	($6)	($6)	($6)	($20)	($21)	($21)	($20)	($24)	($17)	($41)	($42)
Net (Benefit)/Cost	($280)	$0	$0	($0)	($12)	($37)	($35)	($39)	($40)	($40)	($54)	($62)	($85)	($108)	($101)	$13	$14	$12	$16	$21	$22

Medium Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$784	$0	$0	$0	$2	$55	$59	$59	$61	$65	$65	$69	$69	$73	$99	$217	$222	$227	$232	$237	$242
Change in NPC	($886)	$0	$0	$1	($12)	($91)	($92)	($94)	($98)	($111)	($108)	($110)	($125)	($133)	($146)	($155)	($159)	($167)	($179)	($161)	($126)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in VOM	($21)	$0	$0	$0	($0)	($2)	($2)	($3)	($3)	($3)	($3)	($3)	($2)	($2)	($3)	($3)	($3)	($5)	($5)	($3)	($3)
Change in DSM	($47)	$0	($1)	($1)	($2)	($2)	($4)	($4)	($4)	($4)	($5)	($6)	($7)	($8)	($8)	($9)	($9)	($9)	($9)	($9)	($10)
Change in Deficiency	($6)	$0	$0	$0	$0	($0)	$0	$0	$0	$0	$0	$0	$0	($0)	($2)	($3)	($5)	($0)	($5)	($2)	($3)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($92)	$0	($0)	($0)	($0)	($3)	($3)	($3)	($6)	($6)	($6)	($6)	($6)	($20)	($20)	($20)	($17)	($22)	$11	($43)	($94)
Net (Benefit)/Cost	($268)	$0	($0)	($1)	($13)	($43)	($42)	($44)	($50)	($59)	($58)	($56)	($72)	($91)	($80)	$28	$29	$24	$45	$19	$7

Medium Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$784	$0	$0	$0	$2	$55	$59	$59	$61	$65	$65	$69	$69	$73	$99	$217	$222	$227	$232	$237	$242
Change in NPC	($838)	$0	$0	$0	($13)	($91)	($92)	($94)	($100)	($113)	($109)	($111)	($127)	($138)	($154)	($164)	($169)	($156)	($142)	($86)	($12)
Change in Emissions	($17)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($9)	($8)	($9)	($8)	($9)	($5)	($2)
Change in VOM	($19)	$0	$0	$0	($0)	($2)	($2)	($3)	($3)	($3)	($3)	($3)	($2)	($3)	($3)	($3)	($3)	($3)	($3)	($2)	($1)
Change in DSM	($44)	$0	$0	($1)	($1)	($2)	($3)	($3)	($4)	($4)	($5)	($7)	($7)	($8)	($8)	($9)	($9)	($9)	($9)	($9)	($9)
Change in Deficiency	($6)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($2)	($3)	($5)	($4)	($6)	($1)	$2
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($193)	$0	$0	$0	($0)	($3)	($3)	($3)	($6)	($6)	($6)	($6)	($6)	($19)	($19)	($19)	($17)	($44)	($69)	($151)	($247)
Net (Benefit)/Cost	($333)	$0	$0	($0)	($13)	($43)	($41)	($44)	($52)	($60)	($59)	($57)	($74)	($95)	($95)	$11	$11	$2	($7)	($18)	($27)

Medium Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$784	$0	$0	$0	$2	$55	$59	$59	$61	$65	$65	$69	$69	$73	$99	$217	$222	$227	$232	$237	$242
Change in NPC	($786)	$0	$0	$1	($12)	($86)	($87)	($89)	($94)	($106)	($102)	($104)	($118)	($127)	($143)	($153)	($152)	($69)	($71)	($135)	($135)
Change in Emissions	($107)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($9)	($19)	($28)	($34)	($37)	($34)	($37)	($17)	($18)	($28)	($30)
Change in VOM	($17)	$0	$0	$0	($0)	($2)	($2)	($2)	($3)	($3)	($3)	($3)	($2)	($2)	($2)	($2)	($2)	($1)	($1)	($2)	($2)
Change in DSM	($52)	$0	($1)	($1)	($2)	($3)	($4)	($4)	($4)	($5)	($7)	($7)	($8)	($9)	($10)	($10)	($10)	($10)	($10)	($10)	($10)
Change in Deficiency	($7)	$0	$0	($0)	$0	$0	($0)	$0	$0	$0	$0	$0	$0	($0)	($2)	($2)	($2)	($3)	($3)	($4)	($9)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($224)	$0	$0	$0	($0)	($9)	($9)	($10)	($13)	($13)	($13)	($14)	($14)	($25)	($25)	($26)	($27)	($147)	($148)	($73)	($75)
Net (Benefit)/Cost	($409)	$0	($0)	($1)	($13)	($44)	($43)	($46)	($52)	($61)	($69)	($76)	($101)	($124)	($120)	($10)	($9)	($20)	($19)	($15)	($20)

High Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$784	$0	$0	$0	$2	$55	$59	$59	$61	$65	$65	$69	$69	$73	$99	$217	$222	$227	$232	$237	$242
Change in NPC	($923)	$0	$0	$1	($18)	($110)	($116)	($107)	($112)	($117)	($115)	($116)	($132)	($147)	($140)	($130)	($85)	($149)	($124)	($198)	($189)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in VOM	($18)	$0	$0	$0	($0)	($3)	($3)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($3)	($4)
Change in DSM	($42)	$0	($1)	($1)	($2)	($2)	($2)	($3)	($5)	($5)	($5)	($6)	($6)	($6)	($6)	($7)	($7)	($8)	($8)	($9)	($9)
Change in Deficiency	($12)	$0	$0	$0	$0	$0	$0	$0	$0	($0)	$0	$0	$0	($0)	($2)	($4)	($4)	($13)	($18)	$0	($3)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($319)	$0	$0	$0	($0)	($3)	($3)	($26)	($30)	($30)	($31)	($32)	($32)	($39)	($75)	($94)	($149)	($67)	($109)	($51)	($71)
Net (Benefit)/Cost	($531)	$0	($0)	($1)	($19)	($62)	($64)	($80)	($88)	($90)	($89)	($87)	($103)	($121)	($126)	($19)	($25)	($12)	($29)	($24)	($34)

High Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$784	$0	$0	$0	$2	$55	$59	$59	$61	$65	$65	$69	$69	$73	$99	$217	$222	$227	$232	$237	$242
Change in NPC	($869)	$0	$0	$1	($18)	($110)	($116)	($93)	($95)	($101)	($99)	($99)	($113)	($125)	($120)	($117)	($90)	($146)	($142)	($210)	($226)
Change in Emissions	($17)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($5)	($5)	($4)	($8)	($8)	($12)	($15)
Change in VOM	($16)	$0	$0	$0	($0)	($3)	($3)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($1)	($2)	($2)	($3)	($4)
Change in DSM	($45)	$0	($1)	($1)	($2)	($2)	($2)	($3)	($5)	($5)	($5)	($6)	($7)	($7)	($8)	($8)	($8)	($9)	($9)	($10)	($11)
Change in Deficiency	($10)	$0	$0	$0	$0	$0	$0	$0	$0	($0)	$0	$0	$0	$0	($1)	($2)	($1)	($13)	($16)	($0)	($3)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($387)	$0	$0	$0	($0)	($3)	($3)	($47)	($51)	($52)	($53)	($54)	($55)	($62)	($95)	($108)	($141)	($71)	($84)	($35)	($28)
Net (Benefit)/Cost	($561)	$0	($0)	($1)	($19)	($62)	($64)	($86)	($92)	($95)	($95)	($93)	($107)	($123)	($131)	($24)	($24)	($21)	($31)	($34)	($44)

High Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$784	$0	$0	$0	$2	$55	$59	$59	$61	$65	$65	$69	$69	$73	$99	$217	$222	$227	$232	$237	$242
Change in NPC	($898)	$0	$0	$1	($18)	($108)	($114)	($81)	($81)	($86)	($84)	($83)	($95)	($110)	($126)	($186)	($165)	($158)	($190)	($239)	($246)
Change in Emissions	($94)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($7)	($13)	($17)	($20)	($23)	($17)	($31)	($30)	($34)	($40)	($41)
Change in VOM	($18)	$0	$0	$0	($0)	($3)	($3)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($4)	($3)	($2)	($3)	($4)	($4)
Change in DSM	($42)	$0	($1)	($1)	($1)	($1)	($1)	($3)	($5)	($5)	($5)	($6)	($6)	($6)	($7)	($7)	($8)	($8)	($9)	($10)	($11)
Change in Deficiency	($7)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($0)	$0	($0)	$0	($0)	($2)	($1)	($13)	($5)	($2)	($5)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($352)	$0	$0	$0	($0)	($6)	($6)	($64)	($68)	($70)	($71)	($73)	($74)	($74)	($75)	($46)	($39)	($59)	($45)	$6	$4
Net (Benefit)/Cost	($627)	$0	($0)	($1)	($18)	($62)	($64)	($91)	($95)	($98)	($104)	($108)	($126)	($138)	($135)	($45)	($24)	($44)	($53)	($51)	($62)

Rocky Mountain Power
Corrected Exhibit RMP___(RTL-5SD)
Docket No. 17-035-40
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

CORRECTED
Exhibit Accompanying Supplemental Testimony of Rick T. Link

Estimated Annual Revenue Requirement Results ($ million)

February 2018

Exhibit RMP__(RTL-5SD)

Estimated Annual Revenue Requirement Results ($ million)

Low Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$602	$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenues	($72)	$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,086	$0	$0	$0	$25	$162	$151	$142	$135	$129	$125	$121	$118	$114	$111	$107	$104	$101	$97	$94	$90	$87	$83	$80	$77	$73	$70	$66	$63	$59	$56	$53	$49	$46	$39
Network - Wind	$74	$0	$0	$0	$1	$10	$10	$9	$9	$9	$8	$8	$8	$8	$8	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5	$5	$5	$5	$5	$4
O&M - Wind	$437	$0	$0	$0	$4	$22	$22	$23	$26	$27	$29	$31	$32	$35	$38	$42	$45	$48	$51	$55	$58	$61	$65	$68	$72	$76	$80	$85	$90	$95	$102	$110	$122	$126	$74
Terminal Wind	($39)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($374)
PTCs - Wind	($687)	$0	$0	$0	($20)	($117)	($117)	($121)	($126)	($126)	($130)	($130)	($135)	($135)	($114)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99	$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,500	$0	$0	$0	$21	$159	$146	$131	$120	$114	$105	$101	$93	$90	$109	$222	$219	$217	$215	$213	$212	$211	$210	$209	$208	$196	$196	$196	$196	$197	$199	$203	$211	$211	($223)
System Impacts																																			
NPC	($1,033)	$0	$0	$1	($12)	($85)	($86)	($88)	($87)	($91)	($89)	($89)	($99)	($103)	($110)	($113)	($116)	($120)	($132)	($132)	($132)	($130)	($133)	($136)	($139)	($116)	($119)	($121)	($124)	($127)	($130)	($132)	($136)	($138)	($141)
Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Variable Costs	($140)	$0	($0)	($1)	($3)	($5)	($6)	($8)	($10)	($12)	($13)	($14)	($14)	($15)	($17)	($19)	($17)	($17)	($21)	($17)	($18)	($19)	($20)	($20)	($21)	($17)	($17)	($18)	($18)	($19)	($19)	($20)	($20)	($20)	($21)
System Fixed Costs	($131)	$0	($0)	$0	($0)	($3)	($3)	($3)	($6)	($6)	($6)	($6)	($6)	($18)	($19)	($19)	($32)	($22)	($12)	($27)	($27)	($22)	($22)	($23)	($24)	($20)	($20)	($21)	($21)	($21)	($22)	($22)	($23)	($23)	($24)
Net System Impacts	($1,304)	$0	($0)	($1)	($15)	($93)	($95)	($100)	($103)	($109)	($108)	($110)	($120)	($137)	($146)	($150)	($165)	($160)	($166)	($176)	($177)	($171)	($175)	($179)	($183)	($153)	($156)	($160)	($164)	($167)	($171)	($174)	($179)	($182)	($186)
Net (Benefit)/Cost	$195	$0	($0)	($1)	$6	$66	$51	$32	$17	$5	($4)	($9)	($27)	($47)	($37)	$72	$55	$57	$49	$37	$35	$40	$35	$30	$25	$43	$39	$36	$32	$30	$29	$29	$32	$28	($409)

Low Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$602	$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenues	($72)	$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,086	$0	$0	$0	$25	$162	$151	$142	$135	$129	$125	$121	$118	$114	$111	$107	$104	$101	$97	$94	$90	$87	$83	$80	$77	$73	$70	$66	$63	$59	$56	$53	$49	$46	$39
Network - Wind	$74	$0	$0	$0	$1	$10	$10	$9	$9	$9	$8	$8	$8	$8	$8	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5	$5	$5	$5	$5	$4
O&M - Wind	$437	$0	$0	$0	$4	$22	$22	$23	$26	$27	$29	$31	$32	$35	$38	$42	$45	$48	$51	$55	$58	$61	$65	$68	$72	$76	$80	$85	$90	$95	$102	$110	$122	$126	$74
Terminal Wind	($39)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($374)
PTCs - Wind	($687)	$0	$0	$0	($20)	($117)	($117)	($121)	($126)	($126)	($130)	($130)	($135)	($135)	($114)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99	$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,500	$0	$0	$0	$21	$159	$146	$131	$120	$114	$105	$101	$93	$90	$109	$222	$219	$217	$215	$213	$212	$211	$210	$209	$208	$196	$196	$196	$196	$197	$199	$203	$211	$211	($223)
System Impacts																																			
NPC	($1,003)	$0	$0	$1	($11)	($85)	($85)	($88)	($87)	($91)	($89)	($89)	($99)	($102)	($109)	($111)	($113)	($114)	($116)	($122)	($116)	($124)	($127)	($130)	($133)	($111)	($113)	($116)	($119)	($121)	($124)	($126)	($130)	($132)	($135)
Emissions	($46)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($9)	($9)	($10)	($12)	($14)	($12)	($13)	($9)	($9)	($9)	($10)	($8)	($8)	($8)	($9)	($9)	($9)	($9)	($9)	($10)	($10)
Other Variable Costs	($119)	$0	($0)	($2)	($3)	($6)	($7)	($8)	($11)	($11)	($13)	($14)	($14)	($16)	($18)	($9)	($11)	($7)	($11)	($15)	($20)	($15)	($15)	($16)	($16)	($13)	($14)	($14)	($14)	($15)	($15)	($15)	($16)	($16)	($16)
System Fixed Costs	($173)	$0	($0)	($0)	($0)	($3)	($3)	($3)	($6)	($6)	($6)	($6)	($6)	($17)	($25)	($26)	($22)	($29)	($56)	($32)	($46)	($30)	($31)	($32)	($32)	($27)	($28)	($28)	($29)	($29)	($30)	($31)	($32)	($32)	($33)
Net System Impacts	($1,341)	$0	($0)	($1)	($15)	($93)	($95)	($100)	($104)	($108)	($108)	($109)	($119)	($135)	($160)	($155)	($155)	($162)	($197)	($181)	($196)	($178)	($182)	($186)	($191)	($159)	($163)	($166)	($171)	($174)	($178)	($182)	($186)	($190)	($194)
Net (Benefit)/Cost	$159	$0	($0)	($1)	$6	$66	$51	$32	$16	$5	($4)	($8)	($27)	($45)	($52)	$67	$65	$55	$18	$31	$16	$33	$28	$23	$18	$37	$33	$29	$26	$24	$22	$22	$24	$21	($417)

Low Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$602	$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenues	($72)	$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,086	$0	$0	$0	$25	$162	$151	$142	$135	$129	$125	$121	$118	$114	$111	$107	$104	$101	$97	$94	$90	$87	$83	$80	$77	$73	$70	$66	$63	$59	$56	$53	$49	$46	$39
Network - Wind	$74	$0	$0	$0	$1	$10	$10	$9	$9	$9	$8	$8	$8	$8	$8	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5	$5	$5	$5	$5	$4
O&M - Wind	$437	$0	$0	$0	$4	$22	$22	$23	$26	$27	$29	$31	$32	$35	$38	$42	$45	$48	$51	$55	$58	$61	$65	$68	$72	$76	$80	$85	$90	$95	$102	$110	$122	$126	$74
Terminal Wind	($39)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($374)
PTCs - Wind	($687)	$0	$0	$0	($20)	($117)	($117)	($121)	($126)	($126)	($130)	($130)	($135)	($135)	($114)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99	$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,500	$0	$0	$0	$21	$159	$146	$131	$120	$114	$105	$101	$93	$90	$109	$222	$219	$217	$215	$213	$212	$211	$210	$209	$208	$196	$196	$196	$196	$197	$199	$203	$211	$211	($223)
System Impacts																																			
NPC	($1,096)	$0	$0	$0	($13)	($87)	($87)	($90)	($90)	($95)	($96)	($99)	($114)	($118)	($126)	($127)	($129)	($131)	($135)	($118)	($118)	($139)	($142)	($145)	($149)	($124)	($127)	($130)	($133)	($135)	($138)	($142)	($145)	($148)	($151)
Emissions	($261)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($10)	($20)	($28)	($35)	($44)	($46)	($48)	($50)	($53)	($45)	($45)	($48)	($49)	($50)	($52)	($43)	($44)	($45)	($46)	($47)	($48)	($49)	($50)	($51)	($53)
Other Variable Costs	($77)	$0	$0	($0)	($1)	($3)	($4)	($4)	($5)	($5)	($6)	($6)	($6)	($7)	($10)	($10)	($11)	($11)	($11)	($12)	($15)	($11)	($11)	($12)	($12)	($10)	($10)	($10)	($11)	($11)	($11)	($11)	($12)	($12)	($12)
System Fixed Costs	($146)	$0	$0	$0	($0)	($3)	($3)	($3)	($6)	($6)	($6)	($6)	($6)	($20)	($21)	($21)	($20)	($24)	($17)	($41)	($42)	($25)	($25)	($26)	($27)	($22)	($23)	($23)	($24)	($24)	($25)	($25)	($26)	($26)	($27)
Net System Impacts	($1,579)	$0	$0	($0)	($14)	($92)	($94)	($98)	($101)	($106)	($119)	($131)	($154)	($181)	($200)	($204)	($208)	($215)	($216)	($216)	($221)	($223)	($228)	($233)	($239)	($199)	($204)	($208)	($214)	($218)	($223)	($228)	($234)	($238)	($243)
Net (Benefit)/Cost	($79)	$0	$0	($0)	$7	$67	$52	$33	$19	$8	($14)	($30)	($61)	($91)	($91)	$18	$11	$2	($1)	($3)	($9)	($12)	($18)	($24)	($31)	($4)	($8)	($13)	($18)	($20)	($23)	($24)	($23)	($27)	($466)

Medium Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$602	$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenues	($72)	$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,086	$0	$0	$0	$25	$162	$151	$142	$135	$129	$125	$121	$118	$114	$111	$107	$104	$101	$97	$94	$90	$87	$83	$80	$77	$73	$70	$66	$63	$59	$56	$53	$49	$46	$39
Network - Wind	$74	$0	$0	$0	$1	$10	$10	$9	$9	$9	$8	$8	$8	$8	$8	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5	$5	$5	$5	$5	$4
O&M - Wind	$437	$0	$0	$0	$4	$22	$22	$23	$26	$27	$29	$31	$32	$35	$38	$42	$45	$48	$51	$55	$58	$61	$65	$68	$72	$76	$80	$85	$90	$95	$102	$110	$122	$126	$74
Terminal Wind	($39)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($374)
PTCs - Wind	($687)	$0	$0	$0	($20)	($117)	($117)	($121)	($126)	($126)	($130)	($130)	($135)	($135)	($114)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99	$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,500	$0	$0	$0	$21	$159	$146	$131	$120	$114	$105	$101	$93	$90	$109	$222	$219	$217	$215	$213	$212	$211	$210	$209	$208	$196	$196	$196	$196	$197	$199	$203	$211	$211	($223)
System Impacts																																			
NPC	($1,272)	$0	$0	$1	($12)	($91)	($92)	($94)	($98)	($111)	($108)	($110)	($125)	($133)	($146)	($155)	($159)	($167)	($179)	($161)	($126)	($167)	($171)	($175)	($179)	($149)	($153)	($156)	($160)	($163)	($167)	($170)	($175)	($178)	($182)
Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Variable Costs	($110)	$0	($1)	($1)	($2)	($4)	($6)	($6)	($7)	($7)	($8)	($9)	($9)	($11)	($13)	($15)	($17)	($15)	($19)	($15)	($15)	($16)	($16)	($16)	($17)	($14)	($14)	($15)	($15)	($15)	($16)	($16)	($16)	($17)	($17)
System Fixed Costs	($151)	$0	($0)	($0)	($0)	($3)	($3)	($3)	($6)	($6)	($6)	($6)	($6)	($20)	($20)	($20)	($17)	($22)	$11	($43)	($94)	($26)	($26)	($27)	($28)	($23)	($24)	($24)	($25)	($25)	($26)	($26)	($27)	($28)	($28)
Net System Impacts	($1,533)	$0	($0)	($1)	($15)	($98)	($101)	($103)	($111)	($124)	($123)	($125)	($140)	($164)	($178)	($190)	($193)	($203)	($187)	($218)	($235)	($209)	($213)	($218)	($224)	($187)	($191)	($195)	($200)	($204)	($208)	($213)	($218)	($222)	($227)
Net (Benefit)/Cost	($34)	$0	($0)	($1)	$6	$62	$45	$28	$9	($10)	($18)	($24)	($48)	($74)	($70)	$32	$27	$14	$28	($5)	($23)	$2	($3)	($9)	($15)	$9	$5	$1	($4)	($6)	($9)	($9)	($8)	($12)	($450)

Medium Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$602	$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenues	($72)	$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,086	$0	$0	$0	$25	$162	$151	$142	$135	$129	$125	$121	$118	$114	$111	$107	$104	$101	$97	$94	$90	$87	$83	$80	$77	$73	$70	$66	$63	$59	$56	$53	$49	$46	$39
Network - Wind	$74	$0	$0	$0	$1	$10	$10	$9	$9	$9	$8	$8	$8	$8	$8	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5	$5	$5	$5	$5	$4
O&M - Wind	$437	$0	$0	$0	$4	$22	$22	$23	$26	$27	$29	$31	$32	$35	$38	$42	$45	$48	$51	$55	$58	$61	$65	$68	$72	$76	$80	$85	$90	$95	$102	$110	$122	$126	$74
Terminal Wind	($39)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($374)

Exhibit RMP__(RTL-5SD)

Estimated Annual Revenue Requirement Results ($ million)																																			
PTCs - Wind	($687)	$0	$0	$0	($20)	($117)	($117)	($121)	($126)	($126)	($130)	($130)	($135)	($135)	($114)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99	$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,500	$0	$0	$0	$21	$159	$146	$131	$120	$114	$105	$101	$93	$90	$109	$222	$219	$217	$215	$213	$212	$211	$210	$209	$208	$196	$196	$196	$196	$197	$199	$203	$211	$211	($223)
System Impacts																																			
NPC	($1,181)	$0	$0	$0	($13)	($91)	($92)	($94)	($100)	($113)	($109)	($111)	($127)	($138)	($154)	($164)	($169)	($156)	($142)	($86)	($12)	($148)	($152)	($155)	($159)	($133)	($136)	($139)	($142)	($145)	($148)	($151)	($155)	($158)	($162)
Emissions	($31)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($9)	($8)	($9)	($8)	($9)	($5)	($2)	($6)	($6)	($6)	($6)	($5)	($5)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($7)
Other Variable Costs	($103)	$0	$0	($1)	($2)	($4)	($6)	($6)	($7)	($7)	($8)	($10)	($9)	($11)	($12)	($15)	($17)	($16)	($18)	($13)	($8)	($15)	($15)	($15)	($16)	($13)	($13)	($14)	($14)	($14)	($15)	($15)	($15)	($16)	($16)
System Fixed Costs	($337)	$0	$0	$0	($0)	($3)	($3)	($3)	($6)	($6)	($6)	($6)	($6)	($19)	($19)	($19)	($17)	($44)	($69)	($151)	($247)	($62)	($64)	($65)	($67)	($56)	($57)	($58)	($60)	($61)	($62)	($63)	($65)	($66)	($68)
Net System Impacts	($1,651)	$0	$0	($0)	($15)	($98)	($100)	($103)	($113)	($126)	($124)	($126)	($143)	($168)	($194)	($206)	($211)	($225)	($239)	($255)	($269)	($231)	($236)	($242)	($248)	($207)	($211)	($216)	($222)	($226)	($231)	($236)	($242)	($246)	($252)
Net (Benefit)/Cost	($151)	$0	$0	($0)	$6	$62	$46	$28	$7	($12)	($19)	($25)	($50)	($78)	($85)	$16	$8	($7)	($24)	($42)	($57)	($20)	($26)	($33)	($39)	($11)	($16)	($20)	($26)	($28)	($31)	($32)	($31)	($36)	($474)

Exhibit RMP__(RTL-5SD)

Estimated Annual Revenue Requirement Results ($ million)

Medium Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$602	$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenues	($72)	$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,086	$0	$0	$0	$25	$162	$151	$142	$135	$129	$125	$121	$118	$114	$111	$107	$104	$101	$97	$94	$90	$87	$83	$80	$77	$73	$70	$66	$63	$59	$56	$53	$49	$46	$39
Network - Wind	$74	$0	$0	$0	$1	$10	$10	$9	$9	$9	$8	$8	$8	$8	$8	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5	$5	$5	$5	$5	$4
O&M - Wind	$437	$0	$0	$0	$4	$22	$22	$23	$26	$27	$29	$31	$32	$35	$38	$42	$45	$48	$51	$55	$58	$61	$65	$68	$72	$76	$80	$85	$90	$95	$102	$110	$122	$126	$74
Terminal Wind	($39)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($374)
PTCs - Wind	($687)	$0	$0	$0	($20)	($117)	($117)	($121)	($126)	($126)	($130)	($130)	($135)	($135)	($114)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99	$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,500	$0	$0	$0	$21	$159	$146	$131	$120	$114	$105	$101	$93	$90	$109	$222	$219	$217	$215	$213	$212	$211	$210	$209	$208	$196	$196	$196	$196	$197	$199	$203	$211	$211	($223)
System Impacts																																			
NPC	($1,107)	$0	$0	$1	($12)	($86)	($87)	($89)	($94)	($106)	($102)	($104)	($118)	($127)	($143)	($153)	($152)	($69)	($71)	($135)	($135)	($139)	($142)	($145)	($149)	($124)	($127)	($130)	($133)	($136)	($139)	($142)	($145)	($148)	($151)
Emissions	($184)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($9)	($19)	($28)	($34)	($37)	($34)	($37)	($17)	($18)	($28)	($30)	($33)	($34)	($35)	($36)	($30)	($31)	($31)	($32)	($33)	($33)	($34)	($35)	($36)	($36)
Other Variable Costs	($112)	$0	($1)	($1)	($2)	($5)	($6)	($6)	($7)	($8)	($9)	($9)	($10)	($12)	($14)	($14)	($15)	($14)	($14)	($16)	($22)	($16)	($16)	($16)	($17)	($14)	($14)	($15)	($15)	($15)	($16)	($16)	($16)	($17)	($17)
System Fixed Costs	($371)	$0	$0	$0	($0)	($9)	($9)	($10)	($13)	($13)	($13)	($14)	($14)	($25)	($25)	($26)	($27)	($147)	($148)	($73)	($75)	($64)	($65)	($66)	($68)	($57)	($58)	($59)	($61)	($62)	($63)	($65)	($67)	($68)	($69)
Net System Impacts	($1,774)	$0	($0)	($1)	($15)	($100)	($102)	($105)	($113)	($126)	($134)	($145)	($169)	($198)	($219)	($227)	($231)	($247)	($251)	($252)	($262)	($252)	($257)	($263)	($270)	($225)	($230)	($235)	($241)	($246)	($251)	($257)	($263)	($268)	($274)
Net (Benefit)/Cost	($275)	$0	($0)	($1)	$6	$60	$43	$26	$7	($13)	($29)	($44)	($77)	($108)	($110)	($6)	($12)	($30)	($37)	($39)	($50)	($41)	($47)	($54)	($61)	($29)	($34)	($39)	($45)	($48)	($52)	($53)	($53)	($58)	($497)

High Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																				
Transmission Project Capital Recovery	$602		$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenues	($72)		$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,086		$0	$0	$0	$25	$162	$151	$142	$135	$129	$125	$121	$118	$114	$111	$107	$104	$101	$97	$94	$90	$87	$83	$80	$77	$73	$70	$66	$63	$59	$56	$53	$49	$46	$39
Network - Wind	$74		$0	$0	$0	$1	$10	$10	$9	$9	$9	$8	$8	$8	$8	$8	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5	$5	$5	$5	$5	$4
O&M - Wind	$437		$0	$0	$0	$4	$22	$22	$23	$26	$27	$29	$31	$32	$35	$38	$42	$45	$48	$51	$55	$58	$61	$65	$68	$72	$76	$80	$85	$90	$95	$102	$110	$122	$126	$74
Terminal Wind	($39)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($374)
PTCs - Wind	($687)		$0	$0	$0	($20)	($117)	($117)	($121)	($126)	($126)	($130)	($130)	($135)	($135)	($114)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99		$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,500		$0	$0	$0	$21	$159	$146	$131	$120	$114	$105	$101	$93	$90	$109	$222	$219	$217	$215	$213	$212	$211	$210	$209	$208	$196	$196	$196	$196	$197	$199	$203	$211	$211	($223)
System Impacts																																				
NPC	($1,290)	0	$0	$0	$1	($18)	($110)	($116)	($107)	($112)	($117)	($115)	($116)	($132)	($147)	($140)	($130)	($85)	($149)	($124)	($198)	($189)	($159)	($162)	($166)	($170)	($142)	($145)	($148)	($152)	($155)	($158)	($162)	($166)	($169)	($173)
Emissions	$0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Variable Costs	($108)	0	$0	($1)	($1)	($2)	($4)	($4)	($5)	($7)	($8)	($7)	($8)	($8)	($9)	($10)	($13)	($13)	($23)	($28)	($12)	($16)	($16)	($16)	($16)	($17)	($14)	($14)	($15)	($15)	($15)	($16)	($16)	($16)	($17)	($17)
System Fixed Costs	($512)	0	$0	$0	$0	($0)	($3)	($3)	($26)	($30)	($30)	($31)	($32)	($32)	($39)	($75)	($94)	($149)	($67)	($109)	($51)	($71)	($84)	($86)	($87)	($90)	($75)	($76)	($78)	($80)	($82)	($84)	($85)	($88)	($89)	($91)
Net System Impacts	($1,910)	0	$0	($0)	($1)	($20)	($117)	($123)	($139)	($149)	($155)	($154)	($156)	($172)	($195)	($225)	($237)	($247)	($239)	($261)	($261)	($276)	($258)	($264)	($270)	($276)	($231)	($236)	($241)	($247)	($252)	($257)	($263)	($270)	($275)	($281)
Net (Benefit)/Cost	($411)	0	$0	($0)	($1)	$1	$43	$23	($8)	($29)	($41)	($49)	($55)	($79)	($105)	($116)	($15)	($27)	($22)	($46)	($48)	($64)	($47)	($54)	($61)	($68)	($35)	($40)	($45)	($51)	($54)	($58)	($60)	($59)	($64)	($504)

High Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$602	$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenues	($72)	$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,086	$0	$0	$0	$25	$162	$151	$142	$135	$129	$125	$121	$118	$114	$111	$107	$104	$101	$97	$94	$90	$87	$83	$80	$77	$73	$70	$66	$63	$59	$56	$53	$49	$46	$39
Network - Wind	$74	$0	$0	$0	$1	$10	$10	$9	$9	$9	$8	$8	$8	$8	$8	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5	$5	$5	$5	$5	$4
O&M - Wind	$437	$0	$0	$0	$4	$22	$22	$23	$26	$27	$29	$31	$32	$35	$38	$42	$45	$48	$51	$55	$58	$61	$65	$68	$72	$76	$80	$85	$90	$95	$102	$110	$122	$126	$74
Terminal Wind	($39)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($374)
PTCs - Wind	($687)	$0	$0	$0	($20)	($117)	($117)	($121)	($126)	($126)	($130)	($130)	($135)	($135)	($114)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99	$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,500	$0	$0	$0	$21	$159	$146	$131	$120	$114	$105	$101	$93	$90	$109	$222	$219	$217	$215	$213	$212	$211	$210	$209	$208	$196	$196	$196	$196	$197	$199	$203	$211	$211	($223)
System Impacts																																			
NPC	($1,227)	$0	$0	$1	($18)	($110)	($116)	($93)	($95)	($101)	($99)	($99)	($113)	($125)	($120)	($117)	($90)	($146)	($142)	($210)	($226)	($155)	($158)	($162)	($166)	($139)	($142)	($145)	($149)	($151)	($155)	($158)	($162)	($165)	($169)
Emissions	($31)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($5)	($5)	($4)	($8)	($8)	($12)	($15)	($6)	($6)	($6)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($7)	($7)
Other Variable Costs	($108)	$0	($1)	($1)	($2)	($4)	($4)	($5)	($7)	($7)	($7)	($8)	($8)	($9)	($10)	($12)	($11)	($24)	($28)	($14)	($18)	($16)	($16)	($16)	($17)	($14)	($14)	($15)	($15)	($15)	($16)	($16)	($16)	($17)	($17)
System Fixed Costs	($587)	$0	$0	$0	($0)	($3)	($3)	($47)	($51)	($52)	($53)	($54)	($55)	($62)	($95)	($108)	($141)	($71)	($84)	($35)	($28)	($87)	($89)	($90)	($93)	($77)	($79)	($81)	($83)	($85)	($86)	($88)	($91)	($92)	($94)
Net System Impacts	($1,953)	$0	($0)	($1)	($20)	($117)	($123)	($145)	($153)	($160)	($159)	($162)	($176)	($196)	($230)	($242)	($247)	($248)	($263)	($271)	($287)	($263)	($269)	($275)	($282)	($236)	($241)	($246)	($253)	($257)	($263)	($269)	($276)	($281)	($287)
Net (Benefit)/Cost	($453)	$0	($0)	($1)	$1	$43	$23	($14)	($33)	($47)	($55)	($61)	($83)	($106)	($121)	($20)	($27)	($31)	($48)	($58)	($75)	($53)	($59)	($66)	($74)	($40)	($45)	($50)	($56)	($60)	($63)	($65)	($65)	($70)	($510)

High Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$602	$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenues	($72)	$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,086	$0	$0	$0	$25	$162	$151	$142	$135	$129	$125	$121	$118	$114	$111	$107	$104	$101	$97	$94	$90	$87	$83	$80	$77	$73	$70	$66	$63	$59	$56	$53	$49	$46	$39
Network - Wind	$74	$0	$0	$0	$1	$10	$10	$9	$9	$9	$8	$8	$8	$8	$8	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5	$5	$5	$5	$5	$4
O&M - Wind	$437	$0	$0	$0	$4	$22	$22	$23	$26	$27	$29	$31	$32	$35	$38	$42	$45	$48	$51	$55	$58	$61	$65	$68	$72	$76	$80	$85	$90	$95	$102	$110	$122	$126	$74
Terminal Wind	($39)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($374)
PTCs - Wind	($687)	$0	$0	$0	($20)	($117)	($117)	($121)	($126)	($126)	($130)	($130)	($135)	($135)	($114)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99	$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,500	$0	$0	$0	$21	$159	$146	$131	$120	$114	$105	$101	$93	$90	$109	$222	$219	$217	$215	$213	$212	$211	$210	$209	$208	$196	$196	$196	$196	$197	$199	$203	$211	$211	($223)
System Impacts																																			
NPC	($1,314)	$0	$0	$1	($18)	($108)	($114)	($81)	($81)	($86)	($84)	($83)	($95)	($110)	($126)	($186)	($165)	($158)	($190)	($239)	($246)	($180)	($184)	($188)	($193)	($161)	($165)	($168)	($173)	($176)	($180)	($184)	($189)	($192)	($196)
Emissions	($163)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($7)	($13)	($17)	($20)	($23)	($17)	($31)	($30)	($34)	($40)	($41)	($30)	($31)	($31)	($32)	($27)	($28)	($28)	($29)	($29)	($30)	($31)	($32)	($32)	($33)
Other Variable Costs	($102)	$0	($1)	($1)	($2)	($4)	($4)	($5)	($6)	($7)	($7)	($8)	($8)	($8)	($9)	($13)	($12)	($24)	($17)	($15)	($20)	($15)	($15)	($16)	($16)	($13)	($14)	($14)	($14)	($15)	($15)	($15)	($16)	($16)	($16)
System Fixed Costs	($480)	$0	$0	$0	($0)	($6)	($6)	($64)	($68)	($70)	($71)	($73)	($74)	($74)	($75)	($46)	($39)	($59)	($45)	$6	$4	($55)	($56)	($58)	($59)	($49)	($50)	($52)	($53)	($54)	($55)	($56)	($58)	($59)	($60)
Net System Impacts	($2,058)	$0	($0)	($1)	($20)	($117)	($123)	($150)	($156)	($163)	($169)	($177)	($195)	($212)	($234)	($262)	($246)	($271)	($285)	($288)	($304)	($280)	($287)	($293)	($300)	($251)	($256)	($262)	($269)	($274)	($280)	($286)	($294)	($299)	($305)
Net (Benefit)/Cost	($559)	$0	($0)	($1)	$1	$42	$22	($19)	($36)	($49)	($64)	($76)	($102)	($122)	($125)	($40)	($27)	($54)	($70)	($75)	($92)	($70)	($77)	($84)	($92)	($55)	($61)	($66)	($73)	($76)	($80)	($83)	($83)	($88)	($528)

Rocky Mountain Power
Corrected Exhibit RMP___(RTL-2SS)
Docket No. 17-035-40
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

CORRECTED
Exhibit Accompanying Second Supplemental Direct Testimony of Rick T. Link

SO Model and PaR Model Annual Results ($ million) through 2036

February 2018

SO Model Annual Results ($ million)

Low Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$864	$0	$0	$0	$2	$60	$64	$64	$66	$71	$71	$76	$75	$80	$109	$241	$246	$251	$257	$263	$268
Change in NPC	($857)	($0)	$0	$1	($13)	($99)	($100)	($103)	($102)	($106)	($106)	($109)	($122)	($122)	($136)	($132)	($132)	($144)	($158)	($138)	($136)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in DSM	($92)	$0	($0)	($1)	($3)	($4)	($5)	($6)	($9)	($11)	($12)	($14)	($15)	($15)	($15)	($15)	($16)	($17)	($19)	($23)	($25)
Change in System Fixed Cost	($100)	$0	$0	$0	($0)	($3)	($3)	($4)	($7)	($7)	($7)	($7)	($7)	($19)	($19)	($19)	($35)	($22)	($11)	($55)	($57)
Net (Benefit)/Cost	($185)	($0)	($0)	($0)	($15)	($46)	($44)	($49)	($51)	($52)	($54)	($54)	($69)	($76)	($61)	$74	$63	$69	$69	$47	$51

Low Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$864	$0	$0	$0	$2	$60	$64	$64	$66	$71	$71	$76	$75	$80	$109	$241	$246	$251	$257	$263	$268
Change in NPC	($838)	($0)	($0)	$1	($13)	($99)	($100)	($104)	($103)	($107)	($107)	($110)	($124)	($124)	($137)	($126)	($126)	($129)	($130)	($129)	($113)
Change in Emissions	($40)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($9)	($17)	($21)	($19)	($19)	($17)	($25)
Change in DSM	($84)	$0	$0	($1)	($3)	($3)	($4)	($5)	($7)	($9)	($10)	($12)	($12)	($14)	($14)	($16)	($18)	($20)	($21)	($21)	($22)
Change in System Fixed Cost	($109)	$0	($0)	($0)	($0)	($3)	($3)	($4)	($7)	($7)	($7)	($7)	($7)	($19)	($19)	($19)	($13)	($26)	($64)	($49)	($63)
Net (Benefit)/Cost	($208)	($0)	$0	($0)	($15)	($45)	($43)	($49)	($51)	($52)	($53)	($53)	($68)	($76)	($70)	$63	$68	$57	$23	$48	$47

Low Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$864	$0	$0	$0	$2	$60	$64	$64	$66	$71	$71	$76	$75	$80	$109	$241	$246	$251	$257	$263	$268
Change in NPC	($909)	($0)	$1	$1	($13)	($100)	($101)	($104)	($104)	($109)	($111)	($119)	($143)	($151)	($152)	($138)	($136)	($156)	($157)	($156)	($143)
Change in Emissions	($145)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($11)	($20)	($17)	($22)	($37)	($55)	($60)	($45)	($42)	($49)	($63)
Change in DSM	($69)	$0	($2)	($2)	($3)	($3)	($4)	($6)	($7)	($7)	($8)	($8)	($9)	($10)	($11)	($12)	($13)	($14)	($15)	($16)	($16)
Change in System Fixed Cost	($110)	$0	$0	($0)	($0)	($3)	($3)	($4)	($7)	($7)	($7)	($7)	($7)	($21)	($21)	($21)	($21)	($21)	($57)	($55)	($56)
Net (Benefit)/Cost	($370)	($0)	($1)	($1)	($15)	($45)	($44)	($49)	($51)	($51)	($66)	($78)	($102)	($124)	($112)	$15	$16	$16	($15)	($12)	($10)

Medium Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$864	$0	$0	$0	$2	$60	$64	$64	$66	$71	$71	$76	$75	$80	$109	$241	$246	$251	$257	$263	$268
Change in NPC	($1,060)	($0)	$1	$2	($13)	($104)	($107)	($109)	($112)	($125)	($124)	($128)	($143)	($159)	($178)	($195)	($196)	($204)	($230)	($208)	($173)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in DSM	($68)	$0	($2)	($3)	($3)	($4)	($5)	($7)	($7)	($7)	($8)	($8)	($10)	($10)	($11)	($11)	($12)	($12)	($12)	($12)	($13)
Change in System Fixed Cost	($113)	$0	$0	($0)	($0)	($3)	($3)	($4)	($7)	($7)	($7)	($7)	($7)	($21)	($21)	($21)	($19)	($24)	($7)	($63)	($115)
Net (Benefit)/Cost	($377)	($0)	($1)	($1)	($15)	($51)	($51)	($55)	($60)	($67)	($68)	($68)	($85)	($110)	($100)	$14	$19	$12	$7	($20)	($33)

Medium Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$864	$0	$0	$0	$2	$60	$64	$64	$66	$71	$71	$76	$75	$80	$109	$241	$246	$251	$257	$263	$268
Change in NPC	($989)	($0)	$0	$1	($14)	($105)	($109)	($111)	($116)	($128)	($126)	($130)	($145)	($161)	($183)	($203)	($204)	($199)	($203)	($81)	($1)
Change in Emissions	($12)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($7)	($4)	($5)	($7)	($8)	($5)	($2)
Change in DSM	($48)	$0	($0)	($1)	($2)	($2)	($3)	($3)	($4)	($4)	($5)	($7)	($8)	($9)	($9)	($10)	($10)	($10)	($10)	($10)	($10)
Change in System Fixed Cost	($219)	$0	$0	$0	($0)	($3)	($3)	($4)	($7)	($7)	($7)	($7)	($7)	($22)	($22)	($22)	($22)	($39)	($45)	($202)	($299)
Net (Benefit)/Cost	($405)	($0)	($0)	($0)	($15)	($50)	($51)	($54)	($60)	($67)	($67)	($68)	($85)	($111)	($111)	$2	$5	($3)	($9)	($35)	($45)

Medium Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$864	$0	$0	$0	$2	$60	$64	$64	$66	$71	$71	$76	$75	$80	$109	$241	$246	$251	$257	$263	$268
Change in NPC	($910)	($0)	$0	$1	($14)	($94)	($97)	($99)	($103)	($113)	($111)	($122)	($126)	($125)	($172)	($193)	($207)	($86)	($90)	($171)	($177)
Change in Emissions	($103)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($14)	($18)	($37)	($50)	($32)	($14)	($21)	($22)	($23)	($21)	($23)
Change in DSM	($53)	$0	($1)	($1)	($2)	($3)	($3)	($4)	($4)	($5)	($7)	($7)	($8)	($9)	($11)	($11)	($11)	($11)	($11)	($11)	($11)
Change in System Fixed Cost	($287)	$0	$0	$0	($0)	($19)	($19)	($20)	($24)	($24)	($25)	($25)	($26)	($38)	($38)	($39)	($21)	($147)	($148)	($73)	($76)
Net (Benefit)/Cost	($489)	($0)	($0)	($0)	($15)	($55)	($55)	($58)	($64)	($71)	($85)	($96)	($122)	($142)	($143)	($15)	($13)	($14)	($14)	($13)	($19)

High Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$864	$0	$0	$0	$2	$60	$64	$64	$66	$71	$71	$76	$75	$80	$109	$241	$246	$251	$257	$263	$268
Change in NPC	($1,213)	($0)	$0	$1	($21)	($127)	($137)	($130)	($141)	($149)	($149)	($154)	($172)	($188)	($204)	($180)	($125)	($214)	($189)	($279)	($264)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in DSM	($48)	$0	($1)	($1)	($2)	($2)	($2)	($3)	($6)	($6)	($6)	($6)	($8)	($8)	($8)	($8)	($9)	($9)	($10)	($10)	($11)
Change in System Fixed Cost	($303)	$0	$0	($0)	($0)	($3)	($3)	($27)	($30)	($31)	($32)	($32)	($33)	($41)	($55)	($92)	($147)	($57)	($99)	($41)	($67)
Net (Benefit)/Cost	($699)	($0)	($0)	($0)	($22)	($72)	($78)	($96)	($110)	($115)	($116)	($117)	($138)	($157)	($158)	($39)	($35)	($29)	($40)	($68)	($73)

High Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$864	$0	$0	$0	$2	$60	$64	$64	$66	$71	$71	$76	$75	$80	$109	$241	$246	$251	$257	$263	$268
Change in NPC	($1,130)	($0)	$0	$1	($21)	($127)	($137)	($114)	($118)	($130)	($130)	($134)	($150)	($163)	($181)	($128)	($142)	($206)	($198)	($289)	($305)
Change in Emissions	($15)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($5)	($4)	($5)	($7)	($8)	($10)	($12)
Change in DSM	($51)	$0	($1)	($1)	($2)	($2)	($2)	($3)	($6)	($6)	($6)	($7)	($8)	($8)	($9)	($9)	($10)	($10)	($11)	($12)	($12)
Change in System Fixed Cost	($383)	$0	$0	($0)	($0)	($3)	($3)	($48)	($52)	($53)	($54)	($55)	($56)	($63)	($76)	($138)	($129)	($62)	($83)	($27)	($25)
Net (Benefit)/Cost	($716)	($0)	($0)	($0)	($22)	($72)	($78)	($100)	($110)	($117)	($119)	($120)	($139)	($155)	($160)	($39)	($39)	($34)	($43)	($76)	($86)

High Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$864	$0	$0	$0	$2	$60	$64	$64	$66	$71	$71	$76	$75	$80	$109	$241	$246	$251	$257	$263	$268
Change in NPC	($1,131)	($0)	$0	$1	($22)	($125)	($134)	($84)	($87)	($96)	($96)	($99)	($113)	($145)	($177)	($225)	($243)	($224)	($260)	($337)	($348)
Change in Emissions	($67)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($4)	($8)	($11)	($16)	($15)	($8)	($24)	($22)	($29)	($30)	($31)
Change in DSM	($41)	$0	($1)	($1)	($1)	($1)	($1)	($3)	($4)	($5)	($5)	($5)	($6)	($7)	($7)	($7)	($8)	($8)	($9)	($10)	($11)
Change in System Fixed Cost	($406)	$0	$0	($0)	($0)	($7)	($7)	($84)	($89)	($91)	($93)	($95)	($97)	($77)	($74)	($44)	($23)	($49)	($41)	$17	$13
Net (Benefit)/Cost	($781)	($0)	($0)	($0)	($22)	($73)	($78)	($107)	($114)	($120)	($127)	($131)	($151)	($165)	($163)	($44)	($52)	($52)	($82)	($97)	($109)

PaR Stochastic-Mean Results ($ million)*

Low Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$840	$0	$0	$0	$1	$57	$61	$61	$63	$68	$68	$72	$72	$77	$106	$237	$243	$248	$253	$259	$264
Change in NPC	($757)	$0	$0	$1	($12)	($89)	($90)	($92)	($90)	($94)	($92)	($92)	($105)	($109)	($116)	($119)	($121)	($127)	($137)	($124)	($121)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in VOM	($18)	$0	$0	$0	($0)	($2)	($2)	($2)	($2)	($2)	($3)	($3)	($3)	($2)	($2)	($2)	($2)	($3)	($4)	($3)	($3)
Change in DSM	($108)	$0	($1)	($2)	($3)	($5)	($6)	($8)	($10)	($13)	($15)	($16)	($17)	($18)	($18)	($18)	($18)	($19)	($20)	($25)	($27)
Change in Deficiency	($8)	$0	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($3)	($4)	($3)	($2)	($6)	($2)	($4)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($100)	$0	$0	$0	($0)	($3)	($3)	($4)	($7)	($7)	($7)	($7)	($7)	($19)	($19)	($19)	($35)	($22)	($11)	($55)	($57)
Net (Benefit)/Cost	($150)	$0	($0)	($1)	($15)	($41)	($39)	($44)	($47)	($48)	($49)	($45)	($60)	($72)	($53)	$74	$63	$76	$75	$50	$52

Low Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$840	$0	$0	$0	$1	$57	$61	$61	$63	$68	$68	$72	$72	$77	$106	$237	$243	$248	$253	$259	$264
Change in NPC	($756)	$0	$0	$1	($13)	($90)	($90)	($93)	($92)	($96)	($94)	($94)	($107)	($111)	($118)	($120)	($121)	($121)	($119)	($119)	($110)
Change in Emissions	($36)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($12)	($14)	($16)	($17)	($19)	($17)	($19)
Change in VOM	($17)	$0	$0	$0	($0)	($2)	($2)	($2)	($2)	($2)	($3)	($3)	($3)	($2)	($2)	($2)	($2)	($2)	($3)	($2)	($2)
Change in DSM	($93)	$0	$0	($1)	($3)	($4)	($5)	($6)	($8)	($10)	($12)	($13)	($13)	($15)	($16)	($18)	($20)	($21)	($22)	($22)	($24)
Change in Deficiency	($7)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($3)	($3)	($4)	($2)	($7)	($1)	($4)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($109)	$0	($0)	($0)	($0)	($3)	($3)	($4)	($7)	($7)	($7)	($7)	($7)	($19)	($19)	($19)	($13)	($26)	($64)	($49)	($63)
Net (Benefit)/Cost	($179)	$0	($0)	($1)	($15)	($41)	($39)	($44)	($46)	($47)	($47)	($44)	($58)	($71)	($65)	$62	$66	$58	$19	$48	$43

Low Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$840	$0	$0	$0	$1	$57	$61	$61	$63	$68	$68	$72	$72	$77	$106	$237	$243	$248	$253	$259	$264

Change in NPC	($807)	$0	$1	$1	($13)	($90)	($90)	($93)	($92)	($97)	($99)	($102)	($120)	($125)	($131)	($133)	($133)	($134)	($131)	($136)	($137)
Change in Emissions	($159)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($11)	($22)	($30)	($37)	($46)	($48)	($51)	($52)	($54)	($52)	($52)
Change in VOM	($16)	$0	$0	$0	($0)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($3)	($3)	($3)
Change in DSM	($76)	$0	($2)	($3)	($3)	($3)	($5)	($7)	($7)	($7)	($8)	($9)	($10)	($11)	($12)	($13)	($14)	($16)	($16)	($17)	($18)
Change in Deficiency	($8)	$0	($0)	$0	$0	($0)	$0	$0	$0	$0	$0	$0	$0	($1)	($4)	($4)	($3)	($4)	($5)	($2)	($5)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($110)	$0	$0	($0)	($0)	($3)	($3)	($4)	($7)	($7)	($7)	($7)	($7)	($21)	($21)	($21)	($21)	($21)	($57)	($55)	($56)
Net (Benefit)/Cost	($337)	$0	($1)	($1)	($15)	($41)	($39)	($44)	($45)	($45)	($60)	($69)	($97)	($119)	($111)	$17	$18	$19	($13)	($6)	($6)

Medium Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$840	$0	$0	$0	$1	$57	$61	$61	$63	$68	$68	$72	$72	$77	$106	$237	$243	$248	$253	$259	$264
Change in NPC	($941)	$0	$1	$2	($12)	($94)	($96)	($97)	($101)	($114)	($112)	($114)	($133)	($143)	($156)	($166)	($169)	($178)	($200)	($184)	($149)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in VOM	($23)	$0	$0	$0	($0)	($2)	($3)	($3)	($3)	($3)	($3)	($3)	($2)	($3)	($3)	($3)	($3)	($5)	($6)	($4)	($4)
Change in DSM	($76)	$0	($2)	($3)	($4)	($4)	($6)	($7)	($8)	($8)	($9)	($9)	($11)	($11)	($12)	($12)	($13)	($13)	($13)	($13)	($15)
Change in Deficiency	($6)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($2)	($4)	($5)	($1)	($5)	($1)	($4)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($113)	$0	$0	($0)	($0)	($3)	($3)	($4)	($7)	($7)	($7)	($7)	($7)	($21)	($21)	($21)	($19)	($24)	($7)	($63)	($115)
Net (Benefit)/Cost	($319)	$0	($1)	($1)	($16)	($46)	($45)	($49)	($55)	($63)	($63)	($61)	($81)	($101)	($88)	$31	$34	$26	$23	($6)	($22)

Medium Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$840	$0	$0	$0	$1	$57	$61	$61	$63	$68	$68	$72	$72	$77	$106	$237	$243	$248	$253	$259	$264
Change in NPC	($882)	$0	$0	$1	($13)	($95)	($97)	($99)	($104)	($117)	($114)	($115)	($135)	($144)	($162)	($171)	($175)	($176)	($177)	($74)	($3)
Change in Emissions	($18)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($9)	($8)	($9)	($10)	($11)	($5)	($2)
Change in VOM	($21)	$0	$0	$0	($0)	($2)	($3)	($3)	($3)	($3)	($3)	($3)	($2)	($3)	($3)	($3)	($3)	($4)	($5)	($2)	($1)
Change in DSM	($53)	$0	($1)	($1)	($2)	($2)	($4)	($4)	($4)	($5)	($6)	($7)	($9)	($9)	($9)	($11)	($11)	($11)	($11)	($11)	($11)
Change in Deficiency	($4)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($0)	($2)	($3)	($5)	$1	($2)	($1)	($0)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($219)	$0	$0	$0	($0)	($3)	($3)	($4)	($7)	($7)	($7)	($7)	($7)	($22)	($22)	($22)	($22)	($39)	($45)	($202)	($299)
Net (Benefit)/Cost	($357)	$0	($0)	($1)	($15)	($45)	($45)	($47)	($55)	($63)	($62)	($60)	($81)	($102)	($101)	$19	$17	$10	$3	($36)	($52)

Medium Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$840	$0	$0	$0	$1	$57	$61	$61	$63	$68	$68	$72	$72	$77	$106	$237	$243	$248	$253	$259	$264
Change in NPC	($804)	$0	$0	$1	($13)	($85)	($86)	($88)	($92)	($104)	($101)	($101)	($119)	($129)	($144)	($154)	($169)	($80)	($82)	($147)	($148)
Change in Emissions	($116)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($10)	($20)	($29)	($35)	($38)	($36)	($42)	($21)	($22)	($32)	($34)
Change in VOM	($17)	$0	$0	$0	($0)	($2)	($2)	($2)	($3)	($3)	($3)	($3)	($2)	($2)	($2)	($2)	($3)	($1)	($2)	($2)	($3)
Change in DSM	($57)	$0	($1)	($1)	($2)	($3)	($4)	($4)	($4)	($6)	($7)	($7)	($9)	($10)	($11)	($12)	($12)	($11)	($11)	($12)	($12)
Change in Deficiency	($7)	$0	$0	($0)	$0	$0	($0)	$0	$0	$0	$1	$0	$0	($1)	($2)	($2)	($2)	($3)	($3)	($4)	($9)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($287)	$0	$0	$0	($0)	($19)	($19)	($20)	($24)	($24)	($25)	($25)	($26)	($38)	($38)	($39)	($21)	($147)	($148)	($73)	($76)
Net (Benefit)/Cost	($448)	$0	($0)	($1)	($15)	($51)	($50)	($53)	($59)	($68)	($76)	($84)	($113)	($137)	($130)	($7)	($5)	($16)	($16)	($12)	($19)

High Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$840	$0	$0	$0	$1	$57	$61	$61	$63	$68	$68	$72	$72	$77	$106	$237	$243	$248	$253	$259	$264
Change in NPC	($1,021)	$0	$0	$1	($19)	($115)	($122)	($113)	($118)	($123)	($122)	($122)	($143)	($159)	($173)	($154)	($109)	($176)	($152)	($227)	($214)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in VOM	($19)	$0	$0	$0	($0)	($3)	($3)	($3)	($2)	($2)	($3)	($3)	($2)	($2)	($2)	($2)	($2)	($3)	($3)	($4)	($4)
Change in DSM	($52)	$0	($1)	($1)	($2)	($2)	($2)	($3)	($6)	($7)	($7)	($7)	($8)	($9)	($9)	($9)	($10)	($10)	($10)	($11)	($11)
Change in Deficiency	($13)	$0	$0	$0	$0	$1	$0	$0	$1	$0	$0	$0	$1	($0)	($2)	($4)	($3)	($14)	($20)	($2)	($5)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($303)	$0	$0	($0)	($0)	($3)	($3)	($27)	($30)	($31)	($32)	($32)	($33)	($41)	($55)	($92)	($147)	($57)	($99)	($41)	($67)
Net (Benefit)/Cost	($568)	$0	($0)	($1)	($20)	($65)	($68)	($85)	($93)	($95)	($94)	($92)	($114)	($134)	($135)	($23)	($28)	($12)	($30)	($26)	($36)

High Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$840	$0	$0	$0	$1	$57	$61	$61	$63	$68	$68	$72	$72	$77	$106	$237	$243	$248	$253	$259	$264
Change in NPC	($954)	$0	$0	$1	($19)	($115)	($122)	($99)	($101)	($107)	($105)	($106)	($125)	($138)	($153)	($110)	($120)	($171)	($165)	($237)	($249)
Change in Emissions	($21)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($6)	($4)	($6)	($10)	($10)	($14)	($17)
Change in VOM	($18)	$0	$0	$0	($0)	($3)	($3)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($3)	($3)	($4)	($4)
Change in DSM	($55)	$0	($1)	($1)	($2)	($2)	($2)	($3)	($6)	($7)	($7)	($8)	($9)	($9)	($10)	($10)	($10)	($11)	($12)	($13)	($14)
Change in Deficiency	($13)	$0	$0	$0	$0	$1	$0	$0	$1	$0	$0	$0	$1	$0	($1)	($3)	($2)	($15)	($19)	($3)	($5)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($383)	$0	$0	($0)	($0)	($3)	($3)	($48)	($52)	($53)	($54)	($55)	($56)	($63)	($76)	($138)	($129)	($62)	($83)	($27)	($25)
Net (Benefit)/Cost	($603)	$0	($0)	($1)	($20)	($65)	($68)	($91)	($97)	($100)	($100)	($98)	($119)	($135)	($142)	($30)	($26)	($23)	($38)	($38)	($50)

High Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$840	$0	$0	$0	$1	$57	$61	$61	$63	$68	$68	$72	$72	$77	$106	$237	$243	$248	$253	$259	$264
Change in NPC	($955)	$0	$0	$1	($19)	($112)	($119)	($75)	($75)	($79)	($77)	($76)	($93)	($121)	($151)	($208)	($202)	($183)	($211)	($275)	($279)
Change in Emissions	($101)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($7)	($14)	($18)	($23)	($23)	($17)	($34)	($35)	($40)	($43)	($44)
Change in VOM	($19)	$0	$0	$0	($0)	($3)	($3)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($4)	($4)	($3)	($4)	($5)	($5)
Change in DSM	($44)	$0	($1)	($1)	($1)	($1)	($1)	($4)	($5)	($5)	($5)	($6)	($7)	($7)	($7)	($8)	($8)	($9)	($10)	($10)	($12)
Change in Deficiency	($9)	$0	$0	$0	$0	$1	$0	($0)	$1	$0	($0)	($0)	$0	$0	($0)	($2)	($2)	($16)	($4)	($3)	($7)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($406)	$0	$0	($0)	($0)	($7)	($7)	($84)	($89)	($91)	($93)	($95)	($97)	($77)	($74)	($44)	($23)	($49)	($41)	$17	$13
Net (Benefit)/Cost	($694)	$0	($0)	($1)	($20)	($66)	($68)	($103)	($107)	($109)	($116)	($120)	($143)	($153)	($152)	($46)	($30)	($47)	($56)	($59)	($70)

Rocky Mountain Power
Corrected Exhibit RMP___(RTL-3SS)
Docket No. 17-035-40
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

CORRECTED
Exhibit Accompanying Second Supplemental Direct Testimony of Rick T. Link

Estimated Annual Revenue Requirement Results ($ million) through 2050

February 2018

Exhibit RMP__(RTL-3SS)

Estimated Annual Revenue Requirement Results ($ million)

Low Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$602	$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenue	($72)	$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,220	$0	$0	$0	$28	$182	$169	$160	$152	$145	$140	$136	$132	$128	$125	$121	$117	$113	$109	$105	$101	$97	$94	$90	$86	$82	$78	$74	$71	$67	$63	$59	$55	$51	$44
Network - Wind	$83	$0	$0	$0	$2	$11	$11	$10	$10	$10	$10	$9	$9	$9	$9	$8	$8	$8	$7	$7	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5
O&M - Wind	$492	$0	$0	$0	$5	$24	$25	$26	$29	$30	$32	$34	$36	$39	$43	$48	$51	$54	$58	$62	$66	$69	$73	$77	$82	$86	$91	$96	$102	$108	$115	$125	$138	$143	$84
Terminal Wind	($42)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($411)
PTCs - Wind	($767)	$0	$0	$0	($23)	($130)	($130)	($135)	($141)	($140)	($145)	($145)	($151)	($150)	($126)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99	$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,616	$0	$0	$22	$169	$154	$139	$126	$119	$110	$106	$97	$94	$116	$241	$239	$237	$234	$232	$231	$230	$229	$229	$228	$216	$216	$216	$217	$218	$221	$226	$234	$234	($245)	$0
System Impacts																																			
NPC	($1,069)	$0	$0	$1	($12)	($89)	($90)	($92)	($90)	($94)	($92)	($92)	($105)	($109)	($116)	($119)	($121)	($127)	($137)	($124)	($121)	($133)	($136)	($139)	($143)	($121)	($124)	($127)	($130)	($133)	($136)	($139)	($142)	($145)	($148)
Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Variable Costs	($198)	$0	($1)	($2)	($3)	($7)	($8)	($10)	($13)	($15)	($18)	($19)	($20)	($21)	($23)	($25)	($24)	($24)	($30)	($30)	($34)	($28)	($28)	($29)	($30)	($25)	($26)	($27)	($27)	($28)	($28)	($29)	($30)	($30)	($31)
System Fixed Costs	($166)	$0	$0	$0	($0)	($3)	($3)	($4)	($7)	($7)	($7)	($7)	($7)	($19)	($19)	($19)	($35)	($22)	($11)	($55)	($57)	($28)	($29)	($29)	($30)	($26)	($26)	($27)	($28)	($28)	($29)	($29)	($30)	($31)	($31)
Net System Impacts	($1,432)	$0	($0)	($1)	($16)	($99)	($101)	($106)	($110)	($116)	($116)	($118)	($132)	($149)	($159)	($163)	($180)	($172)	($178)	($209)	($212)	($189)	($194)	($198)	($203)	($173)	($176)	($180)	($185)	($188)	($193)	($197)	($202)	($206)	($210)
Net (Benefit)/Cost	$184	$0	($0)	($1)	$6	$71	$54	$33	$16	$4	($7)	($12)	($35)	($55)	($43)	$78	$59	$65	$56	$24	$20	$41	$36	$31	$25	$43	$39	$36	$32	$30	$28	$29	$32	$28	($455)

Low Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$602	$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenue	($72)	$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,220	$0	$0	$0	$28	$182	$169	$160	$152	$145	$140	$136	$132	$128	$125	$121	$117	$113	$109	$105	$101	$97	$94	$90	$86	$82	$78	$74	$71	$67	$63	$59	$55	$51	$44
Network - Wind	$83	$0	$0	$0	$2	$11	$11	$10	$10	$10	$10	$9	$9	$9	$9	$8	$8	$8	$7	$7	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5
O&M - Wind	$492	$0	$0	$0	$5	$24	$25	$26	$29	$30	$32	$34	$36	$39	$43	$48	$51	$54	$58	$62	$66	$69	$73	$77	$82	$86	$91	$96	$102	$108	$115	$125	$138	$143	$84
Terminal Wind	($42)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($411)
PTCs - Wind	($767)	$0	$0	$0	($23)	($130)	($130)	($135)	($141)	($140)	($145)	($145)	($151)	($150)	($126)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99	$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,616	$0	$0	$0	$22	$169	$154	$139	$126	$119	$110	$106	$97	$94	$116	$241	$239	$237	$234	$232	$231	$230	$229	$229	$228	$216	$216	$216	$217	$218	$221	$226	$234	$234	($245)
System Impacts																																			
NPC	($1,061)	$0	$0	$1	($13)	($90)	($90)	($93)	($92)	($96)	($94)	($94)	($107)	($111)	($118)	($120)	($121)	($121)	($119)	($119)	($110)	($130)	($133)	($136)	($140)	($119)	($122)	($124)	($128)	($130)	($133)	($136)	($139)	($142)	($145)
Emissions	($66)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($12)	($14)	($16)	($17)	($19)	($17)	($19)	($13)	($13)	($13)	($14)	($12)	($12)	($12)	($13)	($13)	($13)	($13)	($14)	($14)	($14)
Other Variable Costs	($178)	$0	$0	($1)	($3)	($6)	($7)	($8)	($11)	($12)	($14)	($15)	($15)	($18)	($21)	($23)	($26)	($25)	($32)	($26)	($30)	($26)	($27)	($27)	($28)	($24)	($24)	($25)	($25)	($26)	($27)	($27)	($28)	($28)	($29)
System Fixed Costs	($183)	$0	($0)	($0)	($0)	($3)	($3)	($4)	($7)	($7)	($7)	($7)	($7)	($19)	($19)	($19)	($13)	($26)	($64)	($49)	($63)	($32)	($32)	($33)	($34)	($29)	($29)	($30)	($31)	($31)	($32)	($33)	($34)	($34)	($35)
Net System Impacts	($1,488)	$0	($0)	($1)	($16)	($98)	($100)	($105)	($109)	($115)	($115)	($116)	($130)	($148)	($171)	($176)	($176)	($190)	($234)	($211)	($222)	($201)	($206)	($210)	($215)	($183)	($187)	($191)	($196)	($200)	($204)	($209)	($215)	($218)	($223)
Net (Benefit)/Cost	$127	$0	($0)	($1)	$6	$71	$54	$34	$17	$5	($6)	($10)	($33)	($54)	($55)	$66	$63	$47	$0	$22	$10	$29	$24	$18	$13	$32	$28	$24	$20	$18	$16	$16	$20	$16	($468)

Low Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$602	$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenues	($72)	$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,220	$0	$0	$0	$28	$182	$169	$160	$152	$145	$140	$136	$132	$128	$125	$121	$117	$113	$109	$105	$101	$97	$94	$90	$86	$82	$78	$74	$71	$67	$63	$59	$55	$51	$44
Network - Wind	$83	$0	$0	$0	$2	$11	$11	$10	$10	$10	$10	$9	$9	$9	$9	$8	$8	$8	$7	$7	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5
O&M - Wind	$492	$0	$0	$0	$5	$24	$25	$26	$29	$30	$32	$34	$36	$39	$43	$48	$51	$54	$58	$62	$66	$69	$73	$77	$82	$86	$91	$96	$102	$108	$115	$125	$138	$143	$84
Terminal Wind	($42)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($411)
PTCs - Wind	($767)	$0	$0	$0	($23)	($130)	($130)	($135)	($141)	($140)	($145)	($145)	($151)	($150)	($126)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99	$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,616	$0	$0	$0	$22	$169	$154	$139	$126	$119	$110	$106	$97	$94	$116	$241	$239	$237	$234	$232	$231	$230	$229	$229	$228	$216	$216	$216	$217	$218	$221	$226	$234	$234	($245)
System Impacts																																			
NPC	($1,149)	$0	$1	$1	($13)	($90)	($90)	($93)	($92)	($97)	($99)	($102)	($120)	($125)	($131)	($133)	($133)	($134)	($131)	($136)	($137)	($147)	($150)	($153)	($157)	($134)	($137)	($140)	($143)	($146)	($149)	($152)	($156)	($159)	($163)
Emissions	($279)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($11)	($22)	($30)	($37)	($46)	($48)	($51)	($52)	($54)	($52)	($52)	($51)	($52)	($54)	($55)	($47)	($48)	($49)	($50)	($51)	($52)	($53)	($55)	($56)	($57)
Other Variable Costs	($149)	$0	($2)	($3)	($3)	($5)	($7)	($9)	($10)	($10)	($11)	($11)	($12)	($14)	($18)	($19)	($19)	($22)	($24)	($21)	($25)	($21)	($22)	($22)	($23)	($19)	($20)	($20)	($21)	($21)	($21)	($22)	($22)	($23)	($23)
System Fixed Costs	($185)	$0	$0	($0)	($0)	($3)	($3)	($4)	($7)	($7)	($7)	($7)	($7)	($21)	($21)	($21)	($21)	($21)	($57)	($55)	($56)	($32)	($33)	($33)	($34)	($29)	($30)	($30)	($31)	($32)	($33)	($33)	($34)	($35)	($36)
Net System Impacts	($1,762)	$0	($1)	($1)	($16)	($98)	($100)	($106)	($109)	($114)	($128)	($141)	($168)	($197)	($217)	($221)	($224)	($229)	($267)	($264)	($271)	($251)	($256)	($262)	($269)	($229)	($234)	($239)	($245)	($250)	($255)	($261)	($268)	($272)	($279)
Net (Benefit)/Cost	($147)	$0	($1)	($1)	$6	$71	$54	$33	$18	$6	($18)	($35)	($72)	($103)	($101)	$21	$15	$8	($32)	($32)	($39)	($21)	($27)	($34)	($41)	($13)	($18)	($23)	($29)	($31)	($34)	($35)	($33)	($38)	($523)

Medium Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$602	$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenues	($72)	$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,220	$0	$0	$0	$28	$182	$169	$160	$152	$145	$140	$136	$132	$128	$125	$121	$117	$113	$109	$105	$101	$97	$94	$90	$86	$82	$78	$74	$71	$67	$63	$59	$55	$51	$44
Network - Wind	$83	$0	$0	$0	$2	$11	$11	$10	$10	$10	$10	$9	$9	$9	$9	$8	$8	$8	$7	$7	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5
O&M - Wind	$492	$0	$0	$0	$5	$24	$25	$26	$29	$30	$32	$34	$36	$39	$43	$48	$51	$54	$58	$62	$66	$69	$73	$77	$82	$86	$91	$96	$102	$108	$115	$125	$138	$143	$84
Terminal Wind	($42)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($411)
PTCs - Wind	($767)	$0	$0	$0	($23)	($130)	($130)	($135)	($141)	($140)	($145)	($145)	($151)	($150)	($126)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99	$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,616	$0	$0	$0	$22	$169	$154	$139	$126	$119	$110	$106	$97	$94	$116	$241	$239	$237	$234	$232	$231	$230	$229	$229	$228	$216	$216	$216	$217	$218	$221	$226	$234	$234	($245)
System Impacts																																			
NPC	($1,366)	$0	$1	$2	($12)	($94)	($96)	($97)	($101)	($114)	($112)	($114)	($133)	($143)	($156)	($166)	($169)	($178)	($200)	($184)	($149)	($182)	($186)	($190)	($195)	($166)	($169)	($173)	($178)	($181)	($185)	($189)	($194)	($198)	($202)
Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Variable Costs	($152)	$0	($2)	($3)	($4)	($6)	($8)	($10)	($11)	($11)	($12)	($12)	($13)	($15)	($17)	($19)	($21)	($19)	($24)	($18)	($22)	($20)	($21)	($21)	($22)	($19)	($19)	($19)	($20)	($20)	($21)	($21)	($22)	($22)	($23)
System Fixed Costs	($190)	$0	$0	($0)	($0)	($3)	($3)	($4)	($7)	($7)	($7)	($7)	($7)	($21)	($21)	($21)	($19)	($24)	($7)	($63)	($115)	($33)	($34)	($34)	($35)	($30)	($31)	($31)	($32)	($33)	($33)	($34)	($35)	($36)	($37)
Net System Impacts	($1,708)	$0	($1)	($1)	($17)	($103)	($107)	($110)	($119)	($132)	($131)	($133)	($153)	($178)	($194)	($206)	($209)	($221)	($231)	($264)	($286)	($235)	($241)	($246)	($252)	($214)	($219)	($224)	($230)	($234)	($239)	($245)	($251)	($256)	($261)
Net (Benefit)/Cost	($92)	$0	($1)	($1)	$5	$66	$48	$29	$8	($12)	($21)	($27)	($56)	($84)	($78)	$35	$30	$15	$4	($32)	($55)	($5)	($11)	($17)	($24)	$1	($4)	($8)	($13)	($16)	($18)	($19)	($17)	($22)	($506)

Medium Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$602	$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenues	($72)	$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,220	$0	$0	$0	$28	$182	$169	$160	$152	$145	$140	$136	$132	$128	$125	$121	$117	$113	$109	$105	$101	$97	$94	$90	$86	$82	$78	$74	$71	$67	$63	$59	$55	$51	$44
Network - Wind	$83	$0	$0	$0	$2	$11	$11	$10	$10	$10	$10	$9	$9	$9	$9	$8	$8	$8	$7	$7	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5
O&M - Wind	$492	$0	$0	$0	$5	$24	$25	$26	$29	$30	$32	$34	$36	$39	$43	$48	$51	$54	$58	$62	$66	$69	$73	$77	$82	$86	$91	$96	$102	$108	$115	$125	$138	$143	$84
Terminal Wind	($42)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($411)
PTCs - Wind	($767)	$0	$0	$0	($23)	($130)	($130)	($135)	($141)	($140)	($145)	($145)	($151)	($150)	($126)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99	$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,616	$0	$0	$0	$22	$169	$154	$139	$126	$119	$110	$106	$97	$94	$116	$241	$239	$237	$234	$232	$231	$230	$229	$229	$228	$216	$216	$216	$217	$218	$221	$226	$234	$234	($245)
System Impacts																																			
NPC	($1,249)	$0	$0	$1	($13)	($95)	($97)	($99)	($104)	($117)	($114)	($115)	($135)	($144)	($162)	($171)	($175)	($176)	($177)	($74)	($3)	($157)	($161)	($164)	($168)	($143)	($146)	($150)	($154)	($156)	($160)	($163)	($168)	($171)	($175)
Emissions	($33)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($9)	($8)	($9)	($10)	($11)	($5)	($2)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($7)	($7)	($7)	($7)	($7)
Other Variable Costs	($115)	$0	($1)	($1)	($2)	($4)	($6)	($6)	($7)	($7)	($9)	($10)	($11)	($13)	($15)	($17)	($19)	($14)	($17)	($14)	($12)	($16)	($17)	($17)	($17)	($15)	($15)	($15)	($16)	($16)	($16)	($17)	($17)	($18)	($18)
System Fixed Costs	($385)	$0	$0	$0	($0)	($3)	($3)	($4)	($7)	($7)	($7)	($7)	($7)	($22)	($22)	($22)	($22)	($39)	($45)	($202)	($299)	($71)	($72)	($74)	($76)	($65)	($66)	($67)	($69)	($71)	($72)	($74)	($76)	($77)	($79)
Net System Impacts	($1,782)	$0	($0)	($1)	($16)	($103)	($106)	($109)	($118)	($132)	($130)	($133)	($153)	($179)	($207)	($218)	($226)	($238)	($250)	($295)	($316)	($251)	($256)	($262)	($269)	($229)	($234)	($239)	($245)	($249)	($255)	($261)	($268)	($272)	($278)

Exhibit RMP__(RTL-3SS)

Estimated Annual Revenue Requirement Results ($ million)

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Net (Benefit)/Cost	($167)	$0	($0)	($1)	$6	$67	$48	$30	$8	($12)	($20)	($27)	($56)	($85)	($91)	$23	$13	($1)	($16)	($63)	($85)	($20)	($27)	($33)	($41)	($13)	($18)	($23)	($28)	($31)	($34)	($35)	($33)	($38)	($523)

Medium Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$602	$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenues	($72)	$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,220	$0	$0	$0	$28	$182	$169	$160	$152	$145	$140	$136	$132	$128	$125	$121	$117	$113	$109	$105	$101	$97	$94	$90	$86	$82	$78	$74	$71	$67	$63	$59	$55	$51	$44
Network - Wind	$83	$0	$0	$0	$2	$11	$11	$10	$10	$10	$10	$9	$9	$9	$9	$8	$8	$8	$7	$7	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5
O&M - Wind	$492	$0	$0	$0	$5	$24	$25	$26	$29	$30	$32	$34	$36	$39	$43	$48	$51	$54	$58	$62	$66	$69	$73	$77	$82	$86	$91	$96	$102	$108	$115	$125	$138	$143	$84
Terminal Wind	($42)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($411)
PTCs - Wind	($767)	$0	$0	$0	($23)	($130)	($130)	($135)	($141)	($140)	($145)	($145)	($151)	($150)	($126)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99	$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,616	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
System Impacts																																			
NPC	($1,146)	$0	$0	$1	($13)	($85)	($86)	($88)	($92)	($104)	($101)	($101)	($119)	($129)	($144)	($154)	($169)	($80)	($82)	($147)	($148)	($147)	($150)	($153)	($157)	($134)	($137)	($140)	($143)	($146)	($149)	($153)	($157)	($159)	($163)
Emissions	($200)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($10)	($20)	($29)	($35)	($38)	($36)	($42)	($21)	($22)	($32)	($34)	($36)	($37)	($38)	($39)	($33)	($34)	($35)	($35)	($36)	($37)	($38)	($39)	($39)	($40)
Other Variable Costs	($122)	$0	($1)	($1)	($2)	($5)	($6)	($6)	($7)	($8)	($9)	($10)	($10)	($13)	($16)	($16)	($16)	($16)	($17)	($18)	($24)	($17)	($18)	($18)	($19)	($16)	($16)	($17)	($17)	($17)	($18)	($18)	($19)	($19)	($19)
System Fixed Costs	($451)	$0	$0	$0	($0)	($19)	($19)	($20)	($24)	($24)	($25)	($25)	($26)	($38)	($38)	($39)	($21)	($147)	($148)	($73)	($76)	($70)	($72)	($73)	($75)	($64)	($65)	($67)	($69)	($70)	($71)	($73)	($75)	($76)	($78)
Net System Impacts	($1,920)	$0	($0)	($1)	($16)	($108)	($112)	($114)	($123)	($136)	($144)	($156)	($184)	($214)	($236)	($244)	($248)	($264)	($269)	($270)	($283)	($271)	($277)	($283)	($290)	($247)	($252)	($258)	($265)	($269)	($275)	($281)	($289)	($294)	($301)
Net (Benefit)/Cost	($304)	$0	($0)	($1)	$6	$61	$43	$25	$4	($17)	($35)	($50)	($88)	($120)	($120)	($3)	($9)	($27)	($35)	($38)	($51)	($40)	($47)	($54)	($62)	($31)	($37)	($42)	($48)	($51)	($54)	($56)	($55)	($60)	($545)

High Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$602	$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenues	($72)	$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,220	$0	$0	$0	$28	$182	$169	$160	$152	$145	$140	$136	$132	$128	$125	$121	$117	$113	$109	$105	$101	$97	$94	$90	$86	$82	$78	$74	$71	$67	$63	$59	$55	$51	$44
Network - Wind	$83	$0	$0	$0	$2	$11	$11	$10	$10	$10	$10	$9	$9	$9	$9	$8	$8	$8	$7	$7	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5
O&M - Wind	$492	$0	$0	$0	$5	$24	$25	$26	$29	$30	$32	$34	$36	$39	$43	$48	$51	$54	$58	$62	$66	$69	$73	$77	$82	$86	$91	$96	$102	$108	$115	$125	$138	$143	$84
Terminal Wind	($42)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($411)
PTCs - Wind	($767)	$0	$0	$0	($23)	($130)	($130)	($135)	($141)	($140)	($145)	($145)	($151)	($150)	($126)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99	$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,616	$0	$0	$0	$22	$169	$154	$139	$126	$119	$110	$106	$97	$94	$116	$241	$239	$237	$234	$232	$231	$230	$229	$229	$228	$216	$216	$216	$217	$218	$221	$226	$234	$234	($245)
System Impacts																																			
NPC	($1,452)	$0	$0	$1	($19)	($115)	($122)	($113)	($118)	($123)	($122)	($122)	($143)	($159)	($173)	($154)	($109)	($176)	($152)	($227)	($214)	($184)	($189)	($193)	($198)	($168)	($172)	($176)	($180)	($184)	($188)	($192)	($197)	($200)	($205)
Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Variable Costs	($129)	$0	($1)	($1)	($2)	($4)	($4)	($6)	($8)	($9)	($9)	($9)	($10)	($11)	($13)	($15)	($15)	($27)	($33)	($16)	($20)	($19)	($19)	($20)	($20)	($17)	($18)	($18)	($19)	($19)	($19)	($20)	($20)	($21)	($21)
System Fixed Costs	($483)	$0	$0	($0)	($0)	($3)	($3)	($27)	($30)	($31)	($32)	($32)	($33)	($41)	($55)	($92)	($147)	($57)	($99)	($41)	($67)	($77)	($79)	($80)	($83)	($70)	($72)	($73)	($75)	($77)	($78)	($80)	($82)	($84)	($86)
Net System Impacts	($2,063)	$0	($0)	($1)	($22)	($122)	($129)	($146)	($157)	($163)	($162)	($164)	($186)	($211)	($241)	($261)	($271)	($260)	($284)	($284)	($300)	($281)	($287)	($293)	($301)	($256)	($261)	($267)	($274)	($279)	($285)	($292)	($299)	($305)	($311)
Net (Benefit)/Cost	($448)	($0)	($1)	$0	$47	$25	($7)	($31)	($43)	($52)	($58)	($90)	($117)	($125)	($19)	($32)	($23)	($49)	($52)	($69)	($50)	($57)	($65)	($73)	($40)	($46)	($51)	($58)	($61)	($64)	($66)	($65)	($71)	($556)	$0

High Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$602	$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenues	($72)	$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,220	$0	$0	$0	$28	$182	$169	$160	$152	$145	$140	$136	$132	$128	$125	$121	$117	$113	$109	$105	$101	$97	$94	$90	$86	$82	$78	$74	$71	$67	$63	$59	$55	$51	$44
Network - Wind	$83	$0	$0	$0	$2	$11	$11	$10	$10	$10	$10	$9	$9	$9	$9	$8	$8	$8	$7	$7	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5
O&M - Wind	$492	$0	$0	$0	$5	$24	$25	$26	$29	$30	$32	$34	$36	$39	$43	$48	$51	$54	$58	$62	$66	$69	$73	$77	$82	$86	$91	$96	$102	$108	$115	$125	$138	$143	$84
Terminal Wind	($42)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($411)
PTCs - Wind	($767)	$0	$0	$0	($23)	($130)	($130)	($135)	($141)	($140)	($145)	($145)	($151)	($150)	($126)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99	$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,616	$0	$0	$0	$22	$169	$154	$139	$126	$119	$110	$106	$97	$94	$116	$241	$239	$237	$234	$232	$231	$230	$229	$229	$228	$216	$216	$216	$217	$218	$221	$226	$234	$234	($245)
System Impacts																																			
NPC	($1,365)	$0	$0	$1	($19)	($115)	($122)	($99)	($101)	($107)	($105)	($106)	($125)	($138)	($153)	($110)	($120)	($171)	($165)	($237)	($249)	($176)	($180)	($184)	($189)	($161)	($164)	($168)	($172)	($175)	($179)	($183)	($188)	($191)	($196)
Emissions	($38)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($6)	($4)	($6)	($10)	($10)	($14)	($17)	($7)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($8)	($8)	($8)	($8)	($8)
Other Variable Costs	($132)	$0	($1)	($1)	($2)	($4)	($4)	($5)	($8)	($9)	($9)	($10)	($10)	($11)	($13)	($14)	($14)	($29)	($33)	($19)	($22)	($20)	($20)	($20)	($21)	($18)	($18)	($19)	($19)	($19)	($20)	($20)	($21)	($21)	($22)
System Fixed Costs	($580)	$0	$0	($0)	($0)	($3)	($3)	($48)	($52)	($53)	($54)	($55)	($56)	($63)	($76)	($138)	($129)	($62)	($83)	($27)	($25)	($84)	($86)	($88)	($90)	($77)	($79)	($80)	($83)	($84)	($86)	($88)	($90)	($92)	($94)
Net System Impacts	($2,115)	$0	($0)	($1)	($22)	($122)	($129)	($152)	($160)	($168)	($168)	($170)	($191)	($213)	($248)	($267)	($269)	($271)	($291)	($297)	($314)	($288)	($294)	($301)	($308)	($262)	($268)	($274)	($281)	($286)	($293)	($299)	($307)	($312)	($319)
Net (Benefit)/Cost	($499)	$0	($0)	($1)	$0	$47	$25	($13)	($34)	($49)	($58)	($65)	($94)	($119)	($132)	($26)	($30)	($35)	($57)	($64)	($83)	($57)	($65)	($72)	($80)	($46)	($52)	($58)	($65)	($68)	($72)	($74)	($73)	($78)	($564)

High Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$602	$0	$0	$0	$12	$79	$77	$75	$73	$71	$69	$67	$65	$63	$62	$60	$58	$56	$54	$53	$51	$50	$50	$49	$48	$47	$46	$45	$44	$43	$42	$41	$40	$39	$38
Incremental Transmission Revenues	($72)	$0	$0	$0	($1)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
Capital Recovery - Wind	$1,220	$0	$0	$0	$28	$182	$169	$160	$152	$145	$140	$136	$132	$128	$125	$121	$117	$113	$109	$105	$101	$97	$94	$90	$86	$82	$78	$74	$71	$67	$63	$59	$55	$51	$44
Network - Wind	$83	$0	$0	$0	$2	$11	$11	$10	$10	$10	$10	$9	$9	$9	$9	$8	$8	$8	$7	$7	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6	$6	$5	$5	$5	$5
O&M - Wind	$492	$0	$0	$0	$5	$24	$25	$26	$29	$30	$32	$34	$36	$39	$43	$48	$51	$54	$58	$62	$66	$69	$73	$77	$82	$86	$91	$96	$102	$108	$115	$125	$138	$143	$84
Terminal Wind	($42)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($411)
PTCs - Wind	($767)	$0	$0	$0	($23)	($130)	($130)	($135)	($141)	($140)	($145)	($145)	($151)	($150)	($126)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PPA Cost	$99	$0	$0	$0	$0	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,616	$0	$0	$0	$22	$169	$154	$139	$126	$119	$110	$106	$97	$94	$116	$241	$239	$237	$234	$232	$231	$230	$229	$229	$228	$216	$216	$216	$217	$218	$221	$226	$234	$234	($245)
System Impacts																																			
NPC	($1,432)	$0	$0	$1	($19)	($112)	($119)	($75)	($75)	($79)	($77)	($76)	($93)	($121)	($151)	($208)	($202)	($183)	($211)	($275)	($279)	($204)	($209)	($213)	($219)	($186)	($190)	($194)	($200)	($203)	($208)	($212)	($218)	($222)	($227)
Emissions	($178)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($7)	($14)	($18)	($23)	($23)	($17)	($34)	($35)	($40)	($43)	($44)	($33)	($33)	($34)	($35)	($30)	($30)	($31)	($32)	($33)	($33)	($34)	($35)	($36)	($36)
Other Variable Costs	($112)	$0	($1)	($1)	($2)	($4)	($4)	($5)	($6)	($7)	($7)	($8)	($8)	($9)	($10)	($14)	($14)	($27)	($18)	($18)	($24)	($17)	($17)	($17)	($18)	($15)	($16)	($16)	($16)	($17)	($17)	($17)	($18)	($18)	($19)
System Fixed Costs	($530)	$0	$0	($0)	($0)	($7)	($7)	($84)	($89)	($91)	($93)	($95)	($97)	($77)	($74)	($44)	($23)	($49)	($41)	$17	$13	($53)	($54)	($56)	($57)	($48)	($50)	($51)	($52)	($53)	($54)	($55)	($57)	($58)	($59)
Net System Impacts	($2,251)	$0	($0)	($1)	($21)	($123)	($130)	($165)	($170)	($177)	($184)	($193)	($215)	($230)	($258)	($283)	($273)	($294)	($309)	($318)	($334)	($307)	($314)	($321)	($329)	($280)	($286)	($292)	($300)	($305)	($312)	($319)	($327)	($333)	($341)
Net (Benefit)/Cost	($635)	$0	($0)	($1)	$0	$46	$25	($25)	($44)	($57)	($74)	($87)	($118)	($136)	($142)	($42)	($34)	($58)	($75)	($86)	($103)	($77)	($84)	($92)	($101)	($64)	($70)	($76)	($83)	($87)	($91)	($93)	($93)	($99)	($586)

REDACTED
Rocky Mountain Power
Replacement Exhibit RMP___(RTL-9SS)
Docket No. 17-035-40
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Replacement Exhibit Accompanying Second Supplemental Direct Testimony of Rick T. Link

Oregon IE Assessment

February 2018

BATES WHITE
ECONOMIC CONSULTING

THE INDEPENDENT EVALUATOR'S ASSESSMENT OF PACIFICORP'S FINAL DRAFT 2017R REQUEST FOR PROPOSALS

Presented to:
OREGON PUBLIC UTILITY COMMISSION

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August 10, 2017

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I. INTRODUCTION AND SUMMARY

Bates White, LLC ("Bates White") was chosen by the Public Utility Commission of Oregon ("Commission") to serve as the Independent Evaluator ("Oregon IE" or "IE") for PacifiCorp's ("the Company's") Renewable Request for Proposals ("2017R RFP" or "RFP").[1] This report represents Bates White's analysis of the Final Draft of the RFP as filed with the Commission on August 4, 2017.

The purpose of this report is to identify areas of concern regarding the RFP design and to recommend areas where the Company could improve the RFP to achieve a better outcome. This report complies with the requirements of the Competitive Bidding Guidelines ("Guidelines"),[2] which state:

> The utility will consult with the IE in preparing the RFPs, and the IE will submit its assessment of the final draft RFP to the Commission when the utility files for RFP approval.[3]

A. Background

As a matter of record, we note that this RFP process is taking place under an accelerated schedule. PacifiCorp has requested this accelerated schedule in order to achieve the following:

1. Issue the RFP in time to allow for winning bidders to capture the full value of the Production Tax Credit ("PTC") by placing their projects into service prior to December 31, 2020,[4] and

2. Align with the Company's Certificate of Public Convenience and Necessity ("CPCN") process to expand its transmission system in Wyoming in order to accommodate projects selected in this RFP.

Specifically, we received the initial draft of the RFP from the Company after close of business on Friday, July 21. We provided comments on the initial draft RFP to the Company on Wednesday, July 26. The final draft RFP was filed on Friday August 4. This report is being provided less than a week after that filing. Typically, the review period for a final draft RFP is

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[1] Bates White has significant experience as an Independent Evaluator representing state public utility commissions. We previously monitored PacifiCorp's, 2008 All Source, 2008R-1, 2009R, 2011 All Source, and 2012 Baseload RFPs on behalf of the Oregon Commission. All this work was performed under the name of Boston Pacific Company, Inc. In November of 2016 Boston Pacific entered into a strategic combination with Bates White.

[2] Oregon's Competitive Bidding Guidelines Modified, Public Utility Commission of Oregon, Order No. 14-149, Appendix A, April 30, 2014 ("Competitive Bidding Guidelines").

[3] Competitive Bidding Guidelines, item 6.

[4] RFP, page 1.

more lengthy. For example, in PacifiCorp's 2011 All Source RFP the Final Draft was filed on October 27, 2011 and our assessment of that draft was filed on November 17, 2011.[5] That represents three calendar weeks, as opposed to the one business week afforded here.

The typical concern with such a rushed process, particularly one in which affiliate bids are involved, is that the process is set up for the selection of the affiliate offer and competition will be less than optimal as bidders either cannot or will not offer supply. This is an understandable concern here, particularly since the Company's preferred wind and transmission additions were announced late in the IRP process and the debate over that solution is ongoing.

In this report we make several suggestions to improve participation in the RFP process and make the process more open and fair. In addition, during the process itself, we will independently monitor the process and evaluate all offers, including affiliate bids, to ensure the process is fair. However, 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. The second question would require a much more detailed and time-consuming analysis which would weigh the loss (or partial loss) of the Production Tax Credit ("PTC") against various alternate dispatch scenarios created by a delay in the process and require consideration of schedule delays in not just this process but also the CPCN process in Wyoming. Such an analysis is not possible within this time frame.

The Company has been responsive to our questions and we believe we have been able to make an adequate assessment of the RFP design. We note that PacifiCorp did make several productive changes in response to our initial comments.[6] However, due to this accelerated schedule we will focus this report mainly on suggested changes to the final draft RFP rather than providing a more thorough explanation of the positive aspects of the RFP design.[7] If the Commission feels that more time is needed for consideration of this RFP we do recommend giving more time for stakeholder feedback.

B. Three Unique Risks Present in the RFP

This RFP raises standard concerns regarding any procurement with affiliate offers and PPAs versus utility-owned resources; we make suggestions to address these concerns in this document. However, the timing of this RFP also creates unique risks that are not typically present in an RFP. Three unique risks are as follows:

(1) The Company's 2017 Integrated Resource Plan ("IRP") has not yet been acknowledged by the Commission. As a result, there is a risk that the IRP will not acknowledge the RFP or that the action items driving this RFP may be modified or

[5] See Docket UM-1540. This RFP was also known as the All Source RFP – Resource 2016.

[6] Changes included: a) removing the requirement for bidders to qualify for 100% of the PTC (allowing bidders with 2017 capital purchases to compete), b) moving back the notice of intent to bid due date, and c) removing the requirement for a bidder to have a completed system impact study at bid submission.

[7] Beyond these changes we also have noted additional typographical errors which we will inform the Company of directly.

cancelled;

(2) It cannot be known whether winning projects in this RFP will receive the Production Tax Credit either in part or in full; and

(3) It cannot be known whether or not the Company's proposed transmission project – the 500-kV Gateway Segment D2 Aeolus to Bridger Anticline substation and transmission system (the "Transmission Project" or "Gateway Segment D2") – will be built, and if so, whether it will be built on time.

We address each issue below.

1. Unique Risk #1: Pending IRP

This RFP is based on action items identified in the Company's 2017 IRP. In the Introduction section of the RFP, the Company states:

> As stated in its 2017 Integrated Resource Plan (IRP), PacifiCorp has identified plans to add at least 1,100 megawatts (MW) of new wind resources that will qualify for full federal production tax credits (PTC) and achieve commercial operation by December 31, 2020, in conjunction with implementation of certain Wyoming transmission infrastructure projects within that same timeframe.[8]

Throughout the RFP, the Company explains that it will use the same model and similar evaluation methods to evaluate bids in this RFP as it used in developing its preferred portfolio in the IRP process.[9]

This approach is as reasonable one, and generally consistent with the Commission's Competitive Bidding Guidelines. The IRP is meant to identify needs and to develop an optimal portfolio to address those needs. Interested parties can provide comments on the utility's IRP process and results, and regulators can review and either approve or reject the IRP, depending on its merits. If accepted, RFPs are then used to competitively procure that optimal resource portfolio to meet those needs.

The issue in this case is that the IRP, while filed in Oregon, has not been acknowledged by the Commission.[10] Without an acknowledged IRP, neither the Company nor bidders can know that this RFP is seeking the optimal resource portfolio for the Company's needs. Should the IRP be rejected or substantively modified, this RFP could become moot.

In their filing, PacifiCorp recognizes this issue and states that they have timed the RFP such that the Final Shortlist of bids will be approved after the acknowledgement of the IRP. We would recommend that the Company note this in the RFP document itself so that bidders are more aware of the risk. Our assessment in this RFP design report, by necessity, presumes that the relevant action items from the IRP are acknowledged as proposed. As discussed above, for

[8] RFP, page 1.

[9] See, for example, RFP, page 24.

[10] See Docket No. LC 67.

purposes of this report, we have not conducted an analysis of the IRP, including its identification of resources sought in this RFP as part of its optimal portfolio. We take as given the Company's position that these resources are desirable, per results of the IRP process.

2. Unique Risk #2: Winning Projects' Realization of the PTC

One of the drivers for the accelerated time frame of this RFP is the expiration of the Federal PTC. However, several factors could prevent a winning supplier from realizing the PTC ranging from failure to use equipment that qualifies for a specific vintage of PTC to failure to place a project in service within the required time frame.

Generally, the draft contracts properly commit bidders to their claims regarding PTC qualification. In the case of a Build Transfer Agreement ("BTA"), the bidder pledges that the project will qualify for a given year of PTC treatment and in the Power Purchase Agreement ("PPA"), the bidder will be held to their price offered and cannot increase their price due to failure to claim the PTC.

While we find the language in the BTA and PPA above comforting, there is one additional scenario in which failure to capture the PTC worth noting. That is, a project may be prevented from capturing the PTC if it is delayed by the fact that the Company fails to build and bring online the Gateway Segment D2 Project on time, which, as we explain below, is likely needed by new wind projects to deliver power pursuant to this RFP. In this case, ratepayers must not bear the risk for a project's failure to qualify for the PTC due to PacifiCorp's failure to bring Gateway Segment D2 on line at the pledged time. Bidders – presuming they have held up their other obligations - must also not be at risk for this cost increase.

3. Unique Risk #3: Pending Transmission Project

A third unique risk present in this RFP is its reliance on the Gateway Segment D2 Project. In the RFP, the Company requires eligible projects to be:

> capable of directly interconnecting and delivering energy to PacifiCorp's network transmission system in Wyoming inclusive of the proposed 500-kV Gateway Segment D2 Aeolus to Bridger Anticline substation and transmission system, or capable of delivering energy into PacifiCorp's transmission system in Wyoming with the use of third-party firm transmission service.[11]

It is our understanding that it would be difficult, if not impossible, for new projects to interconnect to the Company's Wyoming system in the absence of the Gateway Segment D2 Project. Should the Wyoming Commission reject Rocky Mountain Power's CPCN proposal, it would create considerable uncertainty with respect to the continued viability of this RFP. Moreover, besides this regulatory risk, there is the risk noted above that, even if approved, the Company may fail to deliver the transmission facilities on time (or at all), which could have

[11] RFP, page 1.

serious implications for winning projects that need to be online by the end of 2020 in order to capture the PTC.

Given this risk, bidders should be allowed to terminate any contractual agreements without penalty should their project fail to become deliverable as the result of the failure of the Gateway Segment D2 Project to be constructed. Again, as noted above, ratepayers should not bear the risk of any project not being able to claim the PTC.

C. Summary

When appraising the design of any competitive procurement process, we begin with the goal of the procurement, which is to get the best deal possible for ratepayers in terms of price, risk, and reliability given market and regulatory conditions. To know if a process will satisfy this goal we look to answer four key questions. These are:

(1) Is the process fair and transparent?
(2) Does the process properly measure and assign risk?
(3) Will the process likely lead to a positive result? And,
(4) Is the process compliant with the Commission's regulatory rules and Bidding Guidelines?

These topics each serve an important function. First, fairness and transparency attract bidders and encourage them to bid aggressively. One cannot have competition without competitors, and the more competitors, the more likely that ratepayers will get a "good deal". Second, effective risk measurement and assignment assure that the winning bids will mitigate ratepayer risk and perform the best under a variety of possible future scenarios. Third, if the procurement does not produce positive results (i.e., signed contracts for new supply) then the entire process will be of marginal value, as the whole purpose of the RFP is to secure the lowest cost supply for ratepayers, when accounting for risk. Fourth, the process must be in line with Commission rules and Competitive Bidding Guidelines as those Guidelines represent the Commission's goals in terms of the type of supply procured and the method by which it is to be procured; goals which have been vetted extensively with all stakeholders. For further discussion on these topics, please see Appendix A.

Our key suggestions can be broken down into several points. We group them below by (a) Fairness and Transparency, (b) Risk Measurement and Assignment, (c) Producing a Positive Result and (d) Compliance with Commission Guidelines. All are discussed more thoroughly in Section II.

1. Fairness and Transparency

Our suggestions on this topic include:

- The RFP should not be limited to new projects; "repowered" and uncommitted existing projects should also qualify provided they are "new" to the PacifiCorp system and can meet the other requirements to participate in this RFP, e.g.

interconnection to the Wyoming system.

- Credit requirements should be clearly defined and account for step-in rights.
- More information should be provided regarding QF contracts which would claim a share of the transmission capacity created by the Gateway Segment D2 Project.
- Clarification should be provided regarding the calculation of the Success Fee.
- The penalties in the PPA for failing to meet a project's Guaranteed Availability should be adjusted, as explained in detail below.

2. Addressing Uncertainty and Assigning Risk

We make six recommendations on this topic:

- PacifiCorp's self-build "benchmark" bids should be held to their assumptions regarding cost and performance.
- Bidders should not bear the risk of PacifiCorp failing to construct the Gateway Segment D2 Transmission Project.
- If PacifiCorp receives approval to complete the Gateway Segment D2 Project, but misses the Commercial Operations Date ("COD") of the project, ratepayers and bidders should be held harmless.
- Price scoring should not be "force ranked, as explained further below.
- The impact of cost overruns on the Gateway Segment D2 Project should be assessed in the RFP evaluation process.
- "Change Orders" which increase the cost of the project should not be paid for by ratepayers.

3. Producing a Positive Result

We make three recommendations on this topic:

- Projects should be required to provide only one year of wind data, not two.
- Stakeholders should provide comment regarding offers on Company's benchmark bid sites and PacifiCorp should provide comment regarding the impact of RFP schedule delays.

- Qualification language regarding litigation against the Company should be limited, as explained further below.

4. Compliance with Commission Competitive Bidding Guidelines

The Commission's Guidelines lay out the rules for a competitive bidding process in Oregon. All qualifying RFPs must meet the standards put forth in those guidelines. We believe the draft RFP meets most of the Guidelines. The exception, as noted above, is that the IRP which produced this procurement plan has yet to be acknowledged by the Commission.

II. DETAILED DISCUSSION OF THE RFP

The following section contains our complete review of the RFP. The review is focused on our four evaluation criteria: (a) fairness and transparency, (b) risk measurement and assignment, (c) producing a positive result, and (d) compliance with appropriate Commission Guidelines. Again, due to the limited review window we focus mainly on changes that would improve the RFP design.

A. Fairness and Transparency

Fairness, in our definition, means that all bidders are treated the same. All bidders want to know that they are competing on a "level playing field," and that they can win the RFP by offering the best deal in terms of price and risk allocation. Transparency means that all parties can clearly understand the RFP requirements, products solicited and evaluation methods.

An important part of ensuring a fair and transparent RFP is making sure that the evaluation is based on objective criteria and that the evaluation method and criteria to be used are clearly explained to bidders. This is why "price only" procurements, where bidders all agree to sign an identical contract and price is the only deciding factor in choosing winners, are considered to be the most transparent form of procurement.

With a long-term, unit contingent procurement, a strict price-only offer is oftentimes not realistic. The procurement must account for the fact that different transaction types and technologies require different contracts and that each bidder has their own preferences and limits on terms such as liquidated damages and force majeure language.

In light of these challenges, the RFP attempts to use a "price mostly" evaluation methodology. The initial shortlist is comprised of price and non-price scores which are given weights of 80% and 20%, respectively. This means that bids with good prices will, generally speaking, be at the top of the bid ranking. The analyses applied to the final shortlist are all focused on determining which portfolios serve ratepayers at the lowest cost under a variety of different scenarios. While there is not a strict standard contract, a draft contract is presented in the RFP and bidders that propose major changes from the draft contract are penalized. In addition, the Company reserves the right to reject any bid after consultation with the IE, which could include bids with contract changes that shift excessive risk onto the ratepayer.

1. The RFP should not be limited to new projects; "repowered" and uncommitted existing projects should also qualify

The RFP currently limits participation to new wind projects only.[12] To enhance fairness, we would recommend expanding participation to uncommitted wind resources, both "repowered" wind projects and existing wind resources. Both such resources would meet PacifiCorp's definition of "new" in the sense that these types of resources should represent an expansion of the Company's wind portfolio. Bidders would need to substantiate the fact that they are uncommitted and meet all the other requirements of the RFP.

[12] RFP, page 1.

Given that the Company is interested in using repowered wind resources as part of its portfolio going forward it would seem to be reasonable to allow them here as well as long as they can meet the other requirements for projects in this RFP. On June 30, 2017, the Company's Wyoming affiliate, Rocky Mountain Power, filed for approval of its own proposal to repower twelve of its own wind resources, located in Wyoming, Oregon, and Washington. That portfolio – which currently has a nameplate capacity of 999.1 MW – would be increased by the repowering to 1,096.8 MW, an increase of 97.7 MW.[13]

2. Credit requirements should be clearly described and account for contractual rights

One important issue for bidders in any RFP is the amount of credit they will have to post as performance assurance for their contract. The draft RFP provides some description of the basic methodology PacifiCorp will use to determine the bidder's credit requirements, however, they have not provided a "credit matrix" which spells out specific amounts due based on project size and transaction type. Based on conversations with the Company, we understand that the Company is currently creating the credit matrix. The Company must distribute this as soon as possible so that other parties can perform their own assessment of the requirements. At a minimum, the credit matrix (as we describe it) must be part of the final RFP that is issued at the end of August.

While we cannot, at this time, provide a thorough assessment of the credit requirements, we do take note of one phrase in the RFP which causes some concern. PacifiCorp states that it views the credit exposure of PPAs as "the cost [it] would incur in the event the resource failed to reach commercial operation by December 31, 2020 or the bidder failed at any time during the life of the contract."[14] Our concern is that PacifiCorp would calculate exposure (and, therefore, the credit requirement) for a PPA over the life of the entire 20-year contract. This would be, to our knowledge, at odds with past practices, which assumed that the Company could use their step-in rights laid out in the pro forma PPA to bring the project to proper commercial operation, limiting its exposure to a much smaller time frame—typically 12-18 months. We recommend the Company stay consistent with this practice in order to avoid creating a disincentive to bidders offering PPAs.

3. The Company should provide updates regarding potential QF contracts

In its June 28, 2017 IRP Update filing PacifiCorp states that the Gateway Segment D2 Project will allow for an additional 320 MW of new qualifying facility ("QF") resources to be imported into the system.[15] PacifiCorp also mentioned this at the RFP stakeholder workshop.

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[13] Rocky Mountain Power, "Application of Rocky Mountain Power for an Order Approving Nontraditional Ratemaking Related to Wind Repowering," June 30, 2017 ("Repowering Proposal"), Exhibit RMP___(RTL-1) Page 1 of 1.

[14] RFP Appendix D – page 5.

[15] PacifiCorp 2017 Integrated Resource Plan Energy Vision 2020 Update, July 28, 2017, page 4.

Our understanding is that these new contracts – if signed – would reduce the amount of new supply the Company would take in this RFP. Assuming this is the case, we would recommend that the Company both (1) state this fact clearly in the RFP and (2) provide updates to bidders if/when these contracts are finalized. This will ensure that bidders are fully aware of a key factor in the bid selection for this RFP.

We presume here that, should these contracts be signed, PacifiCorp will simply reduce its quantity selected in this RFP by a commensurate amount. If this is not the case, then the Company should also make this clear in the RFP document.

4. The calculation of the Success Fee should be clarified and included with the Benchmark Resources

PacifiCorp claims that the winning bidders in this RFP will also pay a "Success Fee" to cover the costs of the Oregon and Utah IEs. The only guidance that the Company provides regarding this fee is that "in no event shall the success fee exceed $300,000 dollars per successful winning bid."[16] We would recommend that the Company provide additional information regarding the calculation of this fee so that bidders can properly price it into their bids.

If this is not possible prior to price submission, for example, because the fee depends on the number of winning offers, we would then recommend that, during the evaluation process, $300,000 be added as a line item to each the Benchmark resource bid in order to be on equal footing with other bidders.

5. The PPA should adjust penalties for failing to meet the Guaranteed Availability

Both the PPA and the BTA provide for performance incentives to deliver projects on time and within certain performance specifications. However, two clauses of the PPA – taken together – give us cause for concern. First, in section 11.1.2 of the PPA, covering "Defaults by Seller", the contract states that the seller will be in default if "Seller fails to meet the Guaranteed Availability for two (2) consecutive years."[17] Second, the PPA defines "Guaranteed Availability" as follows:

> Seller guarantees that the annual Availability of the Facility shall be at least ninety five percent (95%) of the calculated Availability…[18]

Together, these two clauses impose potentially onerous requirements on third-party suppliers and could serve to discourage participation or to force bidders to offer BTA agreements instead. For comparison, the PPA included with the 2008R-1 Renewables RFP featured guaranteed availability levels of 70% in year 1, 85% in year 2 and 93% thereafter, and did not terminate for failure to meet these levels.

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[16] RFP page 9.

[17] PPA, section 11.1.2(h).

[18] PPA, section 6.12.1.

Our recommendation would be to remove failure on this issue as a reason for termination. As additional protection, we recommend that the bidder be required to guarantee a level of availability each year, with a potential "ramp-up" in the early years, and provide liquidated damages if they fall short in any given year.

B. Risk Measurement and Assignment

Risk measurement and assignment is essential in any RFP. As a guiding principle, risks should be put on the party best equipped to handle them. Moreover, the evaluation should give credit to bidders who assume more risk than others. In this area, we have several suggested changes.

1. PacifiCorp's self-build "Benchmark" bids should be held to their assumptions regarding cost and operating performance

This RFP features four self-build or "Benchmark" resources that the Company will offer. As the IE, in accordance with Oregon Guidelines, we will review each offer to ensure that all cost estimates are reasonable and that no costs have been omitted from the estimates. We will also score the offers prior to the opening of market bids.

Beyond these protections, we would recommend that the Benchmark offers be held to their cost and performance assumptions as offered, the same as any third-party bidder would. This will help ensure a level playing field for all offers.

2. Bidders should not be penalized if PacifiCorp fails to construct the Gateway Segment D2 Transmission Project

A unique risk of this RFP is that any bids will likely be dependent on the Gateway Segment D2 Project to interconnect to the grid. Should this project not be approved, or fail to be constructed for another reason, bidders (or the Company) could be at risk of having a project that cannot operate. This could place the bidder in default of their contracts. For example, the BTA Agreement has a condition precedent that "PacifiCorp Transmission shall have demonstrated to PacifiCorp, in PacifiCorp's satisfaction, such satisfaction in its discretion, that the Project can be integrated with PacifiCorp Transmission's system as a network resource."[19] If the Transmission Project is not present the bidder could be in violation of this clause and pay a termination payment of $50/kW. To avoid this problem, both the BTA and the PPA should make clear that the contracts may be terminated without penalty if the Gateway Segment D2 Project fails to be constructed.

3. If PacifiCorp receives approval to complete the Gateway Segment D2 Project, but misses the Commercial Operations Date ("COD") of the project, ratepayers and bidders should be held harmless for any cost impacts

To realize the full PTC, winning suppliers will need to come online by the end of 2020. However, as is made clear in the Rocky Mountain Power Wyoming Transmission Application, winning projects in this RFP are likely to be reliant upon the Transmission Project to deliver power. Should the Transmission Project's COD slip beyond the date by which winning projects must come online to recover the PTC, PacifiCorp should hold ratepayers harmless by not passing any increased costs through to ratepayers. Bidders, provided they have done everything else to

[19] BTA Agreement, section 2.7(m)

properly qualify for the PTC level they have pledged, should likewise not be held accountable for this risk.[20]

4. PacifiCorp employs a complex, multi-step approach to select a portfolio of bids; however, the Price Scoring should not be "force ranked"

The RFP details a method for ranking qualifying proposals by a combined price and non-price score. For the price score PacifiCorp will first calculate the "net benefits" of the bid. This equals the levelized benefits of the project (in $/MWh) less the levelized cost of the project. In this case, the benefits are the value of the energy and capacity produced by the project. The Company would then stack the bids from lowest to highest net benefit. The most beneficial bid would be "force ranked" by assigning the maximum price score of 80 points to that bid while the least beneficial bid would be assigned a score of zero. Bids in between would be scored via a linear interpolation.

Our concern with this method is that bids which are relatively similar in net benefits could receive vastly different price scores. Take, for example, the following set of six bids, where the most beneficial bid has a net benefit of $20/MWh and the least beneficial bid has a net benefit of $14/MWh.

Net Benefit ($/MWh)	Price Score
$ 20.00	80.00
$ 18.50	60.00
$ 16.50	33.33
$ 15.50	20.00
$ 15.00	13.33
$ 14.00	-

Here the difference between the top two bids is small, $1.50/MWh, but the score difference is large, equal to the entire non-price score. As noted earlier, the structure of this RFP requires a "price mostly" evaluation – i.e., an evaluation with greater weight on the price score; however, the manner in which this evaluation is proposed would render the non-price factors irrelevant.

To avoid this outcome, we would recommend that the Company score the bids as it has in past RFPs, by looking at the ratio of benefits to costs. For example, in the 2011 All Source RFP, the price score was calculated by dividing the bid benefits by its costs. If costs were equal to or less than 60% of the benefits the full price score was awarded, while if benefits were equal to or more than 140% of costs a score of zero was awarded, with anything in between being linearly

[20] We welcome comment from stakeholders on the best way to contractually mitigate this risk. Solutions may range from a set level of liquidated damages to a more specific replacement cost calculation.

interpolated. During the actual scoring these endpoints (60% and 140%) can be adjusted to provide a proper balance between price and non-price scores.

Beyond the "force ranking" issue noted above, the RFP features a strong plan for assessing risk and selecting bids that perform well given an uncertain future. Bids will be evaluated in a multi-step process based on the same analytical methods used in the Company's IRP. For the initial shortlist evaluation a price score will be determined as noted above. Bids will then be evaluated for non-price characteristics. The non-price factors attempt to quantify some factors that are not included in the bid price. They are grouped into three categories;

- Conformity to RFP Requirements - This category assesses the completeness of the information provided regarding the project location and technical specifications as well as the bidder's experience related to wind projects.
- Project Deliverability - This category assesses the likelihood that the project can be successfully developed, as proposed, meeting the December 2020 in-service date and qualifying for PTCs as promised.
- Transmission Progression - This category examines the bidder's likelihood of obtaining interconnection service to support their in-service date.

The first category will be worth 4 points while the next two will be worth 8 points each, for a total of 20 points. Each category will be scored at 0, 50% or 100% of the points available.

The scores from the price and non-price evaluations will be added together to establish the initial shortlist. PacifiCorp suggests a target threshold for the shortlist of 2,000 MW, recognizing the fact that the threshold is only a guideline, not an absolute limit. This works out to almost twice the targeted amount of 1,270 MW.

The final shortlist analysis will evaluate the bids using the System Optimizer and Planning and Risk (PaR) models to assess risks using both "stochastic" and "scenario" analyses. Scenario analyses examine a single path of a variable or variables while stochastic analyses examine multiple paths for key variables. This approach is appropriate as proposed and is described below.

The final shortlist analysis has three distinct steps. In the first step, the System Optimizer model will determine, for a given assumed path of certain variables (i.e. natural gas prices, carbon emission costs), the least-cost portfolio of resources that can be used to achieve a given reserve margin. PacifiCorp calls these "policy-price" scenarios. The model looks at a given "group" of resources (in this case, the bids from the initial shortlist) and tests each potential combination of resources to see which combination satisfies the Company's need for the lowest cost.

PacifiCorp will "stress test" the selection by looking at multiple policy-price scenarios. The cases will be consistent with the latest approved IRP, but may be updated to reflect more recent data. PacifiCorp will also look at the optimal portfolio without the Gateway Segment D2 Project and new bids, to establish a baseline of additional benefit or cost in each scenario. This analysis will also be valuable in the event that any bids are provided which can interconnect to the system without the Gateway Segment D2 Project.

The key output from the System Optimizer model will be the portfolio of bids that is selected under each scenario. In the second step of the final shortlist analysis each portfolio will be further evaluated in the Planning and Risk (PaR) model via a stochastic analysis. The stochastic analysis assesses five variables. Those five variables are (a) retail loads; (b) natural gas prices; (c) wholesale electricity prices; (d) hydroelectric generation; and (e) thermal unit availability. A possible range for each of these risks is determined based on historical experience. The output will be a range of prices which provide an assessment of the riskiness of the portfolio.

In the third step of the final shortlist analysis selected portfolios will also be re-run as a fixed selection in all the System Optimizer cases. In other words, the model will be configured to use a given portfolio instead of picking the best portfolio from a group of resources. The PVRR of the portfolio will be counted and ranked versus other portfolios. The purpose of this step is to look for portfolios which perform particularly well or badly under a given scenario. This helps evaluators better understand the strengths and weaknesses of each portfolio and avoid making a selection that could put undue risks on ratepayers.

5. PacifiCorp should assess the impact of cost overruns for the Gateway Segment D2 Project.

As noted above, during the final shortlist evaluation PacifiCorp will look at resource choices both with and without the Gateway Segment D2 Project. This is an important step because it will allow the Commission to see the total net benefit (or cost) that the new bids and transmission project provide in a given scenario.

One additional piece of information that we believe would be useful for the Commission is an assessment of the impact of cost overruns for the Transmission Project. This is important since the Company views these two items (new wind and transmission) as linked. While this RFP can be run in a clear and transparent manner resulting in the selection of wind generation projects which provide net benefits to the Company and its ratepayers, these benefits could be wiped away by cost overruns on the transmission side.

Such an assessment is not necessary if the Company agrees to be held to its cost projections regarding the Transmission Project. Absent such assurances, we will be happy to work with the Company to determine the exact form this assessment could take. Possible assessments could include additional production cost modeling or a more simple "breakeven" analysis for each scenario calculating the percentage of cost overrun required to wipe out the benefits of the new projects.

6. The Company should make clear that "Change Orders" which increase the cost of the project will not be allowed and will not be recovered from ratepayers

The draft Pro Forma BTA includes a section regarding Change Orders.[21] While a major construction project typically needs some process for change orders, their presence in the BTA agreement suggests that a BTA bidder can adjust their price as necessary during construction while a PPA bidder cannot. This could serve to bias bidders into offering a less-risky (from their perspective) BTA project.

[21] BTA Agreement – Article 13.

We would recommend that the Company, in the RFP or the contracts, state that no increases in offer prices will be allowed after contract signing. If PacifiCorp wishes, they could allow this option for BTA bidders, provided that ratepayers are not liable for any cost increases.

C. Producing a Positive Result

Beyond fairness and transparency, we still must consider whether there are any other requirements that could keep the RFP from producing a positive result for ratepayers. In other words, are there any barriers to entry or other requirements that would prevent the Company from contracting with resources that would form the lowest cost portfolio when adjusted for risk? This is especially important in this case where the RFP already has a tightly defined product (new Wyoming wind) and that product is dependent on a yet-to-be-built transmission.

1. Projects should have to provide only one year of wind data, not two

As one of its minimum requirements for participation, the RFP requires bidders "to provide two years of wind resource data for a proposed wind project, as validated by a third party engineering firm."[22] Typically, it has been our experience that bidders are required to provide just one year of wind data.[23] That requirement demonstrates that the bidder has developed a credible, serious proposal worth evaluating. To the extent that the project is less developed than other projects, it would be appropriately rated in the non-price evaluation.

2. Stakeholders should provide comment regarding offers on Company sites and the Company should provide feedback on the impact of schedule delays

During the August 2nd stakeholder conference several questions were raised regarding the ability of third-party bidders to make an offer utilizing the Benchmark sites. While this has, to our knowledge, not been the practice in PacifiCorp renewable RFPs, third party bidders have been able to make offers using company sites for conventional resources. For example, in past RFPs bidders could either offer an EPC agreement on a PacifiCorp site or an Asset Purchase and Sale Agreement ("APSA") on a PacifiCorp site.

The benefits of this action are (a) potentially a stronger offer from the benchmark sites and (b) a more transparent process for benchmark development. In the 2011 All Source RFP PacifiCorp essentially moved an internal competitive process for finding an EPC contractor into the RFP itself, providing more transparency to the process.

While offering this transaction type could result in a more robust pool of responses, it is also true that it would likely require a delay in the RFP as the Company would need to prepare site-specific information for bidders to review. A further complicating factor is that PacifiCorp claims they do not have the right to extend such an offer on three of the four sites. They also claim that it is "expected" that the developer of these three sites will submit their own proposal.[24]

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[22] RFP, page 10.

[23] See, for example, Public Service Company of Oklahoma 2013 Wind RFP, issued June 10, 2013, page A-3; Public Service Company of Oklahoma 2016 Wind Energy Resources RFP, issued September 28, 2016, page A-4.

[24] Another factor is that the conventional-site RFPs included Company sites of unique and specific value (e.g. a site with existing generation facilities that other bidders could not acquire) that were paid for by ratepayers. That, to our

Given that the Company has stated that this RFP is time-sensitive, we would recommend that, as part of this proceeding, any bidders interested in offering these types of transactions describe the type of information they would need to prepare a viable, firm offer. In response, PacifiCorp should provide an estimate of the time it would take them to gather and provide the information, and the potential impact that would have on the RFP process along with any roadblocks they see in offering the sites for bid.

3. The minimum qualification requirements regarding litigation against the Company should be modified

The RFP provides a lengthy list of reasons a bidder may find its proposal rejected. One specific reason is that "[t]he bidder, or an affiliate of bidder, is in current litigation with PacifiCorp or has, in writing, threatened litigation against PacifiCorp, respecting an amount in dispute in excess of one hundred thousand dollars."[25]

Our concern with this requirement is that there is no time limit regarding the latter clause and the dollar amount mentioned is quite small, especially in the context of utility projects. Therefore, a bidder could in theory find themselves removed from the process over a small-dollar issue raised years ago by an affiliate. For this reason we would suggest that PacifiCorp modify the definition to match the one used in its 2011 All Source RFP. It read:

> "Bidder is in current material litigation or has threatened material litigation against PacifiCorp. The Company will work with the IE to determine if the Bidder should be excluded from the RFP in the event the Bidder is threatening or in litigation with the Company."[26]

Another, more precise possibility would use the definition from the final draft version of the same RFP which adds that "Material litigation" for purposes of this provision includes:

> a dispute in excess of five (5) million dollars under circumstances in which the Bidder has issued a demand letter to PacifiCorp, the Bidder and PacifiCorp are currently in dispute resolution, the Bidder and PacifiCorp have an unresolved dispute pending or the Bidder has noticed a pending legal action against PacifiCorp.[27]

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knowledge, does not apply to the sites in question, meaning the Company would likely not have any unique advantage over another developer.

[25] RFP, page 10.

[26] PacifiCorp Oregon All Source Request for Proposal 2016 Resource, issued April 4, 2012. Page 34.

[27] PacifiCorp Final Draft Request for Proposals, Docket UM-1540, October 27, 2011. Page 33.

D. Compliance with Commission Guidelines

The final standard we examine is whether the RFP is in compliance with regulatory rules and guidelines. In Oregon, this means that the RFP is in conformance with the Commission's Competitive Bidding Guidelines, which were developed in 2006 and revised in 2014. These Guidelines are important because they were vetted with multiple stakeholders and lay out exactly how the Commission wants a procurement to operate.

Overall, we find the RFP to be in compliance with most of the Guidelines. In this section, we elaborate on each relevant Guideline and how the RFP attempts to meet that Guideline. There are a total of thirteen Guidelines, some of them, for example, the requirement for a closing report, will be complied with at a later date. Below we discuss all relevant Guidelines.

1. Guideline #1 - Need for an RFP

Guideline #1 requires that an RFP be issued for all major resource acquisitions identified within an acknowledged IRP.[28] This RFP is based on the preferred portfolio in the Company's 2017 IRP.[29] That IRP was submitted to the Commission in April and includes an action item for the procurement of 1,100 MW of new wind located in Wyoming paired with the Gateway Segment D2 Project.[30] This was later updated in July to 1,180 MW of new Wyoming wind capacity.[31]

The issue in complying with this Guideline is that the Company's 2017 IRP has not been officially acknowledged by the Commission. PacifiCorp anticipates, based on the procedural schedule in the case, that the IRP will be considered for acknowledgment prior to the Commission consideration of any final shortlist of bids from this RFP in March of 2018.

We believe the RFP can be compliant with this guideline so long as it reflects any Commission ordered alterations required as part of the IRP acknowledgement. This may result in the complete abandonment of the RFP process should the Commission not approve the relevant action items or reject the IRP altogether. We recommend that the Company note this risk in the RFP document so that bidders are aware of the issue.[32]

[28] There are some exceptions, which are covered in Guideline #2.

[29] PacifiCorp 2017 Integrated Resource Plan ("April IRP"), April 1, 2017, page 2, and confirmed in PacifiCorp 2017 Integrated Resource Plan Energy Vision 2020 Update ("July IRP"), July 28, 2017, page 1.

[30] April IRP, pages 16 to 17.

[31] July IRP, page 12, Table 2.2

[32] As noted above, at this point we will not opine on whether the RFP represents a "time-limited resource opportunity of unique value to customers."

2. Guideline #3 and #4 - Affiliate bidding and self-build option

Guideline #3 is not relevant because here are no affiliate bids being offered. Guideline #4 allows for the utility to provide a site-specific self-build option, known as the Benchmark resource. In this case, the Company plans to submit four self-build bids totaling 860 MW.

The RFP calls for an identical evaluation of the Company's self-build benchmark bids and third-party bids.[33] We will work to ensure these bids are held to the same standards as third-party offers.

3. Guideline #5 - Independent Evaluator

Guideline #5 requires the use of an Independent Evaluator to ensure that all offers are treated fairly. The RFP has called for an appropriate role for the IE and IEs are retained by both the Oregon and Utah Commissions. We will work going forward to ensure that all offers are treated fairly.

4. Guideline #6 - RFP design

Guideline #6 requests that the Company provide a draft RFP to all parties and interested persons in the utility's most recent general rate case, IRP and RFP dockets and conduct a stakeholder and bidder workshop on the draft RFP. The utility will then submit the final draft RFP for approval. The IE must be consulted when preparing the RFPs and will submit a report assessing the final draft RFP.

The Company submitted a draft RFP to the IE at the close of business on July 21. We provided comments and asked questions regarding the draft on July 25. In response, the Company made several productive changes including: (1) removing the requirement for bidders to qualify for 100% of the PTC, (2) moving back the notice of intent to bid due date, (3) removing the requirement for a bidder to have a completed system impact study at bid submission. PacifiCorp submitted this revised initial draft RFP to stakeholders and held workshops with interested parties, including bidders, on August 2, 2017 prior to submitting the final draft RFP on August 4.

This Guideline also requires that the RFP set forth minimum bidding requirements and scoring criteria, which this draft RFP does. These are reasonable, subject to the changes noted above. The RFP must also have standard form contracts but allow bidders to negotiate mutually agreeable terms. The RFP does have these contracts and does contemplate this negotiation.[34]

5. Guideline #7 - RFP approval

Guideline #7 states that Commission approval of the RFP will focus on three items: (1) the alignment of the RFP with the latest acknowledged IRP, (2) whether the RFP satisfies the Guidelines, and (3) the overall fairness of the bidding process. We presume that the Commission

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[33] RFP, page 20.

[34] RFP, page 26.

will request comment on this RFP. PacifiCorp has built in a comment period in their schedule and has requested RFP approval at the end of August. As noted above, the comment period in this case is very brief and the Commission may wish to extend the period to obtain additional feedback from stakeholders.

6. Guideline #8 and #9 - Bid scoring

Guideline #8 requires the Company to submit a detailed score for the benchmark bids to the IE prior to opening market bids. PacifiCorp has stated that they will follow this process. We will review each offer to ensure that it is reasonable and has no omitted costs. We will work with the Company to score the bids prior to reviewing third-party offers.

Guideline #9 requires that the initial shortlist selection be based on price and non-price factors, with price scores representing a comparison of the levelized bid cost to forward market prices, and provide resource diversity. Final shortlist selection is to be based on modeling consistent with the IRP. Finally, debt imputation (also known as "debt equivalence") is reserved for the selection of final bids.

The RFP successfully meets each of these standards. As noted above, the initial shortlist features a price and non-price score. The price score is determined by the levelized net benefit of the bid. The non-price score is based on an assessment of project development and compliance with RFP requirements. The final shortlist modeling will use current IRP inputs (in some cases, updated to the most current assumptions) and the models, process and scenarios are the same as used in the latest IRP. Diversity is provided by the fact that (1) multiple sources are allowed to offer and (2) the initial shortlist will be organized by product category, assuring that selections from each category will be considered for the final shortlist.

Finally, the debt equivalence issue is left out of the evaluation process and is instead contemplated as a potential part of the post final-shortlist considerations. Debt imputation, or debt equivalence is a controversial topic driven by the fact that some credit rating agencies view PPAs and Tolling Agreements as the functional equivalent of debt, treating a portion of the payments under these agreements as *hypothetical* debt to the Company's balance sheet. The Commission has the power to request PacifiCorp to obtain an advisory opinion from a credit rating agency if it wishes to substantiate claims of harm from debt equivalence issues. This is a fair solution because the question of possible harm to ratepayers via this debt equivalence issue requires a broader discussion of possible balance sheet effects from self-build options and offsetting risk mitigation with third-party bids.

7. Guideline #10 through 13 - Roles and Responsibilities

The final guidelines involve items that will be addressed as we move through the RFP process. The roles of the IE and Company are laid out in the RFP similar to Guideline #10 and we will hold to these going forward. We will submit a Final Closing Report (Guideline #11) when the Company requests acknowledgement of the Final Short List (Guideline #13) and will keep information confidential (Guideline #12). If there are any issues, we will bring those to the Commission's attention in our Final Closing Report.

APPENDIX A: KEY CRITERIA OF RFP EVALUATION

KEY CRITERIA OF RFP EVALUATION

Our starting point in reviewing any RFP is the basic premise that the purpose of any competitive solicitation should be to get the best deal possible for ratepayers in terms of price, risk, reliability, and environmental performance, given current market and regulatory conditions. In evaluating whether or not the RFP will lead to this goal, we have found it helpful to focus on four key questions: (1) Is the process fair and transparent? (2) Does the process properly measure and assign risk? (3) Will the process likely lead to a positive result? and (4) Is the process compliant with the Commission's regulatory rules and guidelines?

Following is a brief primer as to why these questions are important and some ways in which to achieve positive answers to these questions.

A. FAIRNESS AND TRANSPARENCY

Why is it important?

To achieve a positive outcome for ratepayers the methods of bid evaluation must be fair and transparent to all. Fairness means that all parties are treated equally. This includes not only third party bids, but also utility Benchmark or self-build options. Transparency means that all parties can understand the RFP requirements and evaluation methods. Only if fairness and transparency are present will a large number of competing power suppliers participate and bid aggressively.

Fairness and transparency attract bidders for several reasons. First, if a solicitation is "fair," bidders know that their bid will be considered on equal footing with other bids, and they do not have to worry about their bid losing out to an inferior offer. Second, if a process is transparent, bidders know exactly what is being solicited and how bids will be evaluated. When bidders know that no special privilege will be granted to any bidder and evaluation criteria are laid out clearly, they know that aggressive bidding is the only way to ensure that they win the RFP.

Fairness and transparency also benefit ratepayers. The more bidders, bidding aggressively, that participate in the RFP, the better chance the ratepayers have of receiving a quality offer. Transparency also has the added benefit of letting the ratepayers know just how the winning bids were chosen.

How do we achieve it?

There is no single right way to solicit power and, therefore, there is no single right way to achieve fairness and transparency. In general, a fair and transparent process would involve; (a) all parties bidding under the same terms, (b) a precisely defined product, and (c) a price only or "price mostly" evaluation. The point of these conditions is to make sure that all bidders understand what they are bidding for and how they will be evaluated and that the winner will simply be the bidder who offers the best deal for ratepayers.

An example of these principles in action can be seen in the full requirements solicitations for Standard Offer or Basic Generation Service in PJM. The product for these solicitations is precisely defined as full requirements supply which, in essence, makes each supplier responsible for serving a percentage share of the energy, capacity, and ancillary service needs of a ratepayer class. Bidders offer an amount of supply at a stated price. The winners are simply the bidders who offer to supply at the lowest cost. All bidders, including the utility affiliate, are treated in the same manner and sign the same contracts.

This is not meant to suggest that PacifiCorp must conduct a full-requirements type solicitation, only to provide a real-world demonstration of fairness and transparency. We feel that it is important for parties to understand that these are more than just "principles" but standards that are achievable in the real world.

B. MEASURING AND ASSIGNING RISK

Why is it important?

In reviewing RFPs we look for an evaluation process which, to the best extent possible, recognizes the uncertain nature of the future, that the only thing certain is uncertainty. Today, future values of variables such as gas prices, emissions regulations, and construction cost escalations are unknown. Yet these variables will have a great impact on future ratepayer costs. The impact of new technology could also greatly affect the choice and cost of future supply.

If the exact paths of these variables were known, the selection of new resources would be relatively easy. In reality, there are no certainties about the future, which makes the evaluation process much more complex. The best evaluation process is one which acknowledges the risks that ratepayers face, and incorporates an analysis of those risks into the selection of bids which perform well under many different future scenarios.

The RFP, then, must do two things to take account of risk. First, the evaluation methods must recognize and measure risk. Second, bids must be credited to the extent that they assign risk away from the ratepayers and onto parties better equipped to manage risk.

This focus also assists ratepayers because, if the evaluation clearly accounts for risk, then credit can be given to the bidders who act to shield ratepayers from risk and the lowest-risk bids can be identified. It also encourages innovative risk management. If bidders know that they will stand a greater chance to win, all things being equal, by removing risks from the ratepayer, then they will be encouraged to come up with ways to remove or hedge risk.

How do we achieve it?

To find the best deal for ratepayers, risks must be accurately measured in the evaluation process. There are two chief ways to handle this task. One way is to assign each bidder the same risk profile through a tightly defined product, process, and a contract which holds all bidders to the same risk assignment standard. This method is used in the previously-mentioned full requirements solicitations in areas like New Jersey and Maryland, where all bidders, including utility affiliates, bid by the same rules for the same product and sign standardized contracts.

The second way to measure risk is to review the key risks inherent in each bid and attempt to value each of them separately. This requires sophisticated modeling techniques which model what costs would be incurred for each bid based on changes in key variables. This sort of modeling can take two basic forms, "scenario" modeling or "stochastic" modeling. Scenario modeling examines a single "path" for a given variable and reports what ratepayers would pay given that scenario. Stochastic modeling involves essentially creating multiple "paths" for each variable, basically hundreds of scenario runs at once, which give both an average or expected value of the bid as well as a risk metric such as standard deviation.

The ultimate goal of these exercises is to compare bids with different risk profiles. This comparison is key because the nature and extent of risk varies across technologies and transaction types. For example, for coal-fired technologies the greater risks are linked to capital costs and environmental regulations. In contrast, for natural gas, fuel price risk is the more prominent risk. Similarly, a fixed price pay-for-performance power purchase agreement puts all risks on the bidder, while a cost-plus transaction puts the risk burden on the ratepayer.

C. LEADING TO A POSITIVE RESULT

In reviewing and conducting an RFP, it is always important to keep the end goal in mind, the acquisition of the best deal for ratepayers in terms of risk, reliability, price, and environmental performance, given market conditions. The above prescriptions should aid in that goal, but they do not guarantee it. If, for example, a bidding requirement, say, a credit threshold, disqualifies a wide selection of potential participants, then the likelihood of a good result is lower. With this in mind we also review an RFP with an eye toward items which could affect the participation levels in the RFP.

We note that there are times when the goal of a positive result could come into conflict with the other goals mentioned above. For example, a bidder could present an offer that is attractive, but features a non-fixed (or indicative) price. At this point, it is up to the evaluators to decide whether allowing this bid to be evaluated is appropriate given the fact that other bidders have conformed to the requirement to submit a binding bid. In these cases Bates White views part of the IE's job as providing advice on moving forward in the best interests of ratepayers.

D. COMPLYING WITH COMMISSION RULES AND GUIDELINES

A final topic that we review is compliance with appropriate Commission regulatory rules and guidelines. While these are usually in line with the goals of fairness and transparency and, of course, are geared toward producing a positive result we cannot simply ignore rules and guidelines because they represent the will of regulators and the ratepayers, having been vetted through a public comment process.

BATES WHITE
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September 26, 2017

Bruce Griswold
Resource & Commercial Strategy
PacifiCorp
825 N.E. Multnomah St
Portland, OR 97232

Dear Mr. Griswold:

This letter is to confirm that Bates White, as the Independent Evaluator for the Oregon Public Utility Commission, has reviewed the proposed changes to PacifiCorp's 2017R RFP from the version filed in Docket UM-1845 on August 23, 2017 and approved with conditions by Commission Order 17-345. These changes were made in response to that Order, an Order from the Utah Public Service Commission, and comments from Bates White and the Utah IE.

After review, we have no objections to the changes made.

Please feel free to contact me if you have further questions.

Sincerely,

Frank Mossburg
Managing Director
Bates White, LLC
Washington, DC 20005
Phone: (202) 652-2194

PAGES 29 – 163 OF THIS EXHIBIT ARE HIGHLY CONFIDENTIAL

This highly confidential exhibit contains commercially sensitive information which is considered business confidential information subject to Utah Code 63G-2-305(2) and 63G-2-305(3) to protect it from a Government Records Access and Management Act (GRAMA) request. The Company requests special handling. Please contact Jana Saba at (801) 220-2823 to make arrangements to review.