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Date: March 4, 2022

Re: **Docket No. 21-035-09,** PacifiCorp's 2021 Integrated Resource Plan

Recommendation: Limited Acknowledgement

The Division of Public Utilities (Division) recommends that the Public Service Commission (Commission) acknowledge only the new resource acquisitions in the two-to-four-year window of the Action Plan of PacifiCorp's 2021 Integrated Resource Plan (IRP). The IRP largely adheres to the Commission's Standards and Guidelines.[1] However, there are parts of the Standards and Guidelines that PacifiCorp (Company) failed to meet—in particular, Guideline 3, which mandates that IRPs be developed in consultation with the Commission, the Division, the Office

[1] *Report and Order on Standards and Guidelines*, Docket No. 90-2035-01, June 18, 1992 (Standards and Guidelines)

of Consumer Services, and other interested parties. The Company failed to meet this Guideline by not allowing new natural gas resources in the modeling, including preliminary unsupported estimates of nuclear plant costs and risks, and by not including sufficient public input on these and other topics. This failure resulted in a preferred portfolio that may not be the least-cost, least risk option. For this reason, we recommend that the Commission acknowledge only a portion, as described in the next section.

The IRP may outline plans, plants, and facilities that are in the public interest. Indeed, from a more detached perspective than an IRP, it is likely that the future of safe, adequate, and reliable electricity supplies at reasonable prices includes increased amounts of solar, storage, wind, and supporting dispatchable resources, perhaps including nuclear generation. It seems plain that all states where the Company operates envision a future Company portfolio that is clean, efficient, and poised for sustainability.

However, the IRP is intended to be a rigorous exercise that disciplines the broader conventional wisdom by evaluating all resources to identify the least cost, least risk portfolio. Some of the tasks in an IRP must be substantially resource-agnostic and others are more judgmental, and ought to be. An IRP is not *solely* for identifying the least cost, least risk portfolio. It is also a tool for identifying contingencies and sensitivities that may alter plans and revealing paths to adapting to those potential disruptions. Only by beginning with an evaluation of substantially all proven resource types and then deliberately and transparently adding on other policies and judgments can the process yield this more complete picture of the planning period's options. Even then, the IRP will provide only a rough guide to what should be done moving forward.

An IRP's use should be tempered by humility about its limitations, particularly in its later years. Because of threshold decisions the Company made with little to no meaningful consultation and very limited opportunity to test different modeling options after feedback, the filed IRP suffers from deficiencies that limit its value for planning a least cost, least risk portfolio beyond the two-to-four-year window of the Action Plan. These threshold decisions also limit the IRP's value in revealing other useful knowledge about how the system might react to potential shocks if the Company's plans prove inadequate for whatever reason. While the Division shares the goals of a cleaner, efficient, sustainable system, the IRP suffers from infirmities that render it inadequate as a full review and plan for the planning period.

Key Findings and Recommendations

The Division's key findings and recommendations are presented to the Commission below. Some of the recommendations refer to Standards and Guidelines that were issued by the Commission in the 1992 order, and that the Company is to follow in preparing IRPs.

- The Company failed to meet Guideline 3, which states in part: "PacifiCorp will provide ample opportunity for public input and information exchange…"[2] This failure was caused by two deficiencies: (1) A disorganized meeting schedule, wherein public meetings were frequently cancelled and rescheduled, with meeting materials often not provided until the last minute, and (2) resource modeling decisions that appear inconsistent and inadequate, including a decision to not include new natural gas resources in the main modeling because of permitting and other uncertainties, while including a nuclear facility with speculative numbers, timelines, and numerous uncertainties of its own. The decision not to model new gas resources was presented to stakeholders as a "done deal," after the modeling was already underway.
- Due to the failure to meet Guideline 3, the Division recommends that the Commission not acknowledge the entire IRP. The preferred portfolio should not be entirely acknowledged because if new natural gas plants were modeled, there is a reasonable chance the preferred portfolio would have included a different set of resources. At a minimum, a complete evaluation would have required more grappling with the judgmental factors that were considered regarding the exclusion of natural gas resources. That exercise, with stakeholder input and a quantitative analysis of risk, would have revealed far more than the Company's initial, tersely-explained, decision to not consider new natural gas resources. Therefore, the Division requests that for future IRPs and updates, the "main"

[2] *Id.* at 42.

modeling be performed with proven resource types included. Here, that would have meant new natural gas plants (peaker and baseload).

- The Natrium nuclear plant should not be part of the preferred portfolio due to uncertainty about cost inputs and how cost overruns will be handled. The Division applauds the Company's exploration of new types of generation, but until costs are known with more certainty, the Natrium plant should be modeled as a sensitivity, not in the preferred portfolio. The Division recommends that the part of the preferred portfolio that includes the Natrium plant not be acknowledged. Of course, this does not mean that the Natrium plant is not likely to be part of a least cost, least risk portfolio or in the public interest. Knowledge surrounding the plant is simply not sufficiently well-formed to include the plant at this time.
- The Division recommends that the Action Plan for the most part be acknowledged. The new resource acquisitions in the two-to-four-year window of the Action Plan appear to not be significantly affected by the exclusion of natural gas from the modeling.
- The Division recognizes that certain actions regarding the Natrium plant are in the Action Plan (see Action Item 2c). If the Natrium plant is not acknowledged as part of the preferred portfolio but the Action Plan is acknowledged, the Commission would be in the unique position of having the Action Plan contain an item that is not in the preferred portfolio. However, the Natrium items in Action Plan Item 2c do not require significant capital investments. Due to the long lead time of nuclear plants, actions to prepare for a possible Natrium investment must begin in the Action Plan window. Therefore, the Division has no objection to these Natrium items being in the Action Plan, even though the Natrium plant is not yet recommended for inclusion in the preferred portfolio.
- For future IRPs and updates, if a nuclear plant is included in the preferred portfolio, the risk issues, including cost overruns, should be described in significantly greater detail. Merely stating that ratepayers will not face significant risks is insufficient.

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1. Background

The 2021 IRP was filed late. The Commission approved a delay of the March 31, 2021 deadline[3] in order to allow the results of the 2020 All-Source Request for Proposals (2020AS RFP) to be accounted for in the current IRP planning cycle and to address modeling software issues.[4] The Division did not support the late filing date of the IRP; this lack of support was based on repeated past instances of late filings, leading to a situation where the principle of a timely IRP (filed every other year on March 31) cannot be relied on. This erratic filing schedule results in stakeholders being deprived of the opportunity to review the IRP on a regular basis.[5] Despite the delay and resulting extra time, there remained significant deficiencies in stakeholders' opportunities for meaningful feedback on some issues.

The Company filed the text of its 2021 IRP (Volumes I and II) with the Commission on September 1, 2021. On September 15, 2021, the Company filed the IRP data discs containing supporting data and additional information for the analyses of the IRP. The September 15, 2021, filing also included an errata filing with minor corrections in Volumes I and II of the IRP. The Company did not publish its Supplemental Sensitivity Studies until the September 15, 2021 filing.

One significant change for the 2021 IRP was the use of Plexos modeling, which is a new software for modeling of long-term capacity expansion, hourly dispatch, and stochastic scenarios. The Plexos software allows for endogenous modeling of resource options and associated transmission options, which reduces the number of portfolios that need to be run. To be sure, this change significantly affected the process and timelines. While this change is not likely to be repeated for future IRPs, delays, schedule alterations, and late corrections are becoming the norm.

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[3] The Commission established a March 31 filing date for PacifiCorp's IRP based on the Company's proposed filing date in the docket for the 2008 IRP. See *Report and Order*, Docket No. 09-2035-01, *In the Matter of the Acknowledgement of PacifiCorp's Integrated Resource Plan*, April 1, 2010, p. 57.
[4] The Company filed its request for an extension on February 21, 2022. On March 15, 2021, the Commission approved the Company's request for an extension until September 1, 2021. The IRP was not fully filed until September 15, when data filings were made.
[5] See *Comments from the Division of Public Utilities*, Docket No. 19-035-02, July 22, 2019 (2019 Division Comments), pp. 2-3.

2. Public Input and Stakeholder Process

The Division has in past IRP comments highlighted the Company's poor performance with respect to public input meetings, stakeholder process, distribution of meeting materials, and meeting cancellations.[6] The Division is frustrated and discouraged that it has not been able to bring forth positive change on this front. The Company continues to struggle with providing meeting materials on time, postponing or canceling meetings with short notice, and providing enough time for stakeholder input. While the Division recognizes the complexity of the undertaking, it is the Company's duty to have sufficient personnel and other resources to meet these standards even when other dockets and efforts in various forums overlap with the IRP schedule.

Meeting Dates and Meeting Materials

In the 2019 IRP, the Division, Utah Clean Energy (UCE), and Western Resources Advocates (WRA) all voiced concerns over not having information to review prior to the scheduled public stakeholder meetings.[7] Each of the parties petitioned the Commission to make some type of ruling on providing meeting materials, whether it was three business days in advance, or 48 hours in advance.

As was the case in the 2019 IRP,[8] the Division believes that Guideline 3 of the Commission's Standards and Guidelines was not met in the 2021 IRP. Guideline 3 requires "ample opportunity for public input and information exchange."[9] Guideline 3 also states the following:[10] "The IRP will be developed in consultation with the Commission, its staff, the Division of Public Utilities, the Committee of Consumer Services, appropriate Utah state agencies and interested parties."

The Company has repeatedly committed to provide information in a timely and beneficial manner. In its Reply Comments for the 2019 IRP, the Company committed to do better and

[6] See, e.g., *Comments on PacifiCorp's 2017 IRP*, Docket No. 17-035-16, October 24, 2017, p. 25.
[7] *Order*, Docket No. 19-035-02, May 13, 2020, pp. 18-19.
[8] *Comments from the Division*, Docket No. 19-035-02, February 4, 2020, p. 3, pp. 25-26.
[9] *Standards and Guidelines*, p. 42.
[10] *Id*. at 41-42.

asked the Commission to not make a firm requirement regarding the time that meeting materials should be provided. For the 2021 IRP, the Company promised its best effort to provide materials three days in advance of meetings,[11] and the Commission accepted the Company's commitment for future processes. In its 2019 IRP Order, the Commission did state the following:

> If a party can demonstrate, in the future, a pattern of unwillingness to provide meeting materials far enough in advance of meetings to allow parties to reasonably prepare, we could consider re-opening the Guidelines to make them more specific.[12]

The Commission should do so.

After the Company received its extension, it proposed the following meeting schedule starting in April of 2021:[13]

Table 1 IRP Public Meeting Dates Post-Extension (Proposed)

Meeting Dates	Meeting Length*
April 22-23, 2021	13.5
May 27-28, 2021	13.5
June 24-25, 2021	13.5
July 29-30, 2021	13.5
August 12, 2021	7
Total Hours	**61**
* Assumes 7 hours on day one, 6.5 hours on day two, lunch not factored in	

That proposed schedule had 61 hours of meetings after the extension. The following table shows the dates and times of the actual 2021 IRP public input meetings after the extension was granted (long meetings had lunches, but again these were not subtracted from the meeting length):

[11] *Order*, Docket No. 19-035-02, May 13, 2020, p. 18.
[12] *Id.* at 20.
[13] Email from IRP Mailbox, Feb. 23, 2021.

Table 2 IRP Public Meeting Dates Post-Extension (Actual)

Date of Meeting	Length of Meeting (hours)
4/23/2021	2
6/25/2021	7
7/30/2021	7
8/6/2021	2
8/27/2021	7
10/1/2021	2
Total Meeting Stakeholder Time After Extension	**27**

The total post-extension meeting length (27 hours) was less than half of what was initially scheduled (61 hours). This was due to the modeling results being late, leading to the cancellation of some meetings, and the postponement of others. At the crucial period of IRP discussion of modeling results, the opportunity for stakeholder input was drastically reduced. Furthermore, meeting materials at this crucial time were not distributed far enough ahead of time to permit meaningful review.

As the dates in the next table show, the Company did not provide meeting materials three days in advance for most of its 2021 IRP meetings after the extension. For most meetings after the extension, materials were provided the evening before or the morning of the meeting, or as the meeting started.[14] Early in the process the Company provided materials in advance of the meetings. However, during the crucial period of the modeling, development, and selection of the IRP preferred portfolio, the Company consistently failed to provide materials in advance for stakeholders to review.

[14] This table does not show all meetings that were reduced to two or three hours in length.

Table 3 Date of Meeting Materials Distribution

Date of Meeting	Date and Time Meeting Slides Were Distributed	Notes
6/18/2020 - 6/19/2020	6/15/2020 at 5:51 p.m.	
7/30/2020 - 7/31/2020	7/27/2020 at 8:17 p.m.	
9/17/2020	9/14/2020 at 4:41 p.m.	
10/22/2020	10/19/2020 at 5:42 p.m.	
11/16/2020	11/11/2020 at 4:02 a.m.	
12/3/2020	12/2/2020 at 5:54 p.m.	The evening before the meeting, after close of business
6/25/2021	06/24/2021 at 8:20 p.m.	The evening before the meeting, after close of business
7/30/2021	07/30/2021 at 8:58 a.m.	The morning of the meeting
8/6/2021	08/06/2021 at 9:36 a.m.	The morning of the meeting
8/27/2021	08/27/2021 at 9:22 a.m.	The morning of the meeting
10/1/2021	10/01/2021 at 9:05 a.m.	The morning of the meeting

This lack of access to information severely hindered the Division's (and other parties') ability to actively participate in the development, selection, and review of the 2021 preferred portfolio, which has harmed the public interest and undermined faith in the IRP's results and process.

In previous IRPs, the Division has expressed similar concerns. In Docket No. 13-2035-01, the Commission stated the following: "When parties have consensus proposals for changes to the Guidelines, we will consider them going forward."[15] There appears to be a non-Company consensus forming regarding mandating meeting materials in advance; UCE, WRA, and the Division have all requested action on this issue.[16]

By not having access to meeting materials, parties are severely handicapped, especially in a fast-moving planning process where inputs are locked in prior to when the Company begins the analytical modeling. When new information is presented during a public input meeting, the time to give input that can be actionable has often passed, with the Company having already moved forward. In the case of the decision to not model new natural gas plants, by the time parties asked questions about the decision, the Company was already well into running Plexos modeling.

[15] *Report and Order*, Docket No. 13-2035-01, January 2, 2014, p. 16.
[16] Docket No. 19-035-02, Comments from the Division, Comments from Utah Clean Energy, and Comments of Western Resources Advocates, February 4, 2020.

The Decision Not to Model New Natural Gas Resources

At the July 30, 2020 public input meeting, the Company provided supply-side characteristics for natural gas plants in the 2021 IRP. In the September 7, 2020, meeting materials, the Company provided performance and costs for gas resources, as it has in past IRPs. At that time, there was no indication that the Company was planning to manually force the model to not select new natural gas plants as proxy resources. This decision to block a (possibly) cost-effective resource from being modeled for the base (indicative) case is unprecedented.

The Company cancelled the April 2021 and May 2021 meetings, so the first notice of a decision to not model new natural gas resources was in the indicative cases the Company had developed for the June 25, 2021 meeting. Materials for that meeting were provided after the close of business the day before the meeting. The Company stated that it excluded new gas proxy resources in portfolio development. This decision was not made with any transparency or discussion—it was simply revealed to stakeholders at the June 25, 2021 meeting. A significant decision to exclude gas resources should have been made known to stakeholders months earlier, when IRP stakeholder comments could have made a difference. The Division received clarification of this decision at the July 30, 2021 meeting, and provided stakeholder comments on August 3, 2021 requesting gas proxy resources be modeled. By this time, the Company had already decided on its indicative portfolio, and the Division's comments were too late to effect change. The Company would have had to re-run the modeling, turning off the algorithm that blocked new natural gas plants as proxy resources.

The Company did offer to run a sensitivity (S-04) in response to the Division's request; however, the results of this sensitivity were provided on September 15, 2021, 15 days after the 2021 IRP had been published. In other words, the sensitivity did not inform the IRP. The Division is not stating here that the Company's "no gas" decision was correct or not correct but is pointing out that the process did not allow the Division or other stakeholders to participate in the decision.

This example demonstrates the shortcomings of not allowing stakeholders access to meeting materials in advance of meetings, and demonstrates the Company's lack of transparency concerning critical assumptions. The Company knew, or should have known, that parties would have significant consultation on the model runs to be performed. The Company evidently decided it either had no time for or interest in adjusting its modeling plans for parties' feedback. These decisions had significant implications for the resources selected during the planning period. The merits of the decision to not model natural gas are discussed further in Section 6 below.

Cancelled Meetings

The Company cancelled or postponed several meetings at the last minute, and in some cases shortened meetings that were originally scheduled to be two full-day meetings, holding one-day or partial-day meetings in their place.

The original IRP schedule as set forth in the materials for the June 18-19, 2020 public meeting was as follows:

- June 18-19, 2020 – General Public Input Meeting
- July 30-31, 2020 – Public Input Meeting
- August (TBD), 2020 – Conservation Potential Assessment Technical Workshop
- September 17-18, 2020 – Public Input Meeting
- October 22-23, 2020 – Public Input Meeting
- December 3-4, 2020 – Public Input Meeting
- January 14-15, 2021 – Public Input Meeting
- February 25-26, 2021 – Public Input Meeting

Early in the 2021 IRP process the Division was hopeful that the Company had resolved its delays and procedural issues. The Company held its regularly scheduled, two-day public input meetings on June 18-19, 2020, and on July 30-31, 2020. After that, meetings were rarely held on the scheduled dates, or for the scheduled duration. The Company eventually asked for an extension for the due date of its 2021 IRP, and the Commission granted the extension on March

15, 2021.[17] The February 10, 2021 meeting was mainly a discussion of the request for extension. On February 23, 2021, the Company sent an email with a new IRP schedule as follows:

- April 22-23, 2021 – Thursday – Friday
- May 27-28, 2021 – Thursday – Friday
- June 24-25, 2021 – Thursday – Friday
- July 29-30, 2021 – Thursday – Friday
- August 12, 2021 – Thursday (if needed)

These scheduled meetings for the most part did not take place as scheduled. The delays and modifications are listed below:

- On April 20, 2021, the Company cancelled the April 22 meeting, and condensed the April 23 meeting into a 2.5-hour meeting. On May 24, the Company cancelled the May 27-28, 2021 meetings and said the June 24-25 meetings would discuss preliminary portfolio results.
- On June 16, 2021, the Company cancelled the June 24 meeting, but said the June 25 meeting would take place as planned. On June 24 at 8:20 pm, the Company sent the June 25 meeting materials. The Company called for an August 6 meeting, in addition to the August 12 meeting.
- On July 26, the Company cancelled the July 29 meeting. The July 30 meeting materials were sent out July 30 at 8:58 a.m. (the meeting started at 10:00 am). The July 30 meeting was 7 hours.
- The August 6 meeting materials were sent the morning of August 6 at 9:36 am. The meeting was 2.5 hours.
- On August 10, 2021, the August 12 meeting was moved back a week to August 19, 2021.
- On August 18, 2021, at 6:00 p.m., the August 19 meeting was pushed back a day to August 20.
- On August 19, 2021, at 5:00 p.m., the August 20 meeting was pushed back to August 26. Later that evening, the meeting was pushed back to August 27, 2021.

PacifiCorp held its final public input meeting on August 27, 2021, just three days before filing its 2021 IRP. The Company presented its preferred portfolio for the first time at the August 27, 2021 meeting. Several stakeholders raised concerns at the August 27 meeting about whether the preferred portfolio would be available to review and whether PacifiCorp would consider pushing

[17] *Order Granting Request for Extension to File*, Docket No: 21-035-09, March 15, 2021.

back the IRP filing date result given the uncertainty.[18] The Company filed its incomplete IRP on September 1 and submitted the data disks supporting the IRP two weeks later, on September 15.

The Division recognizes that occasionally, the Company should have the ability to change meeting times as needed. However, the Company has taken this ability to an extreme. For example, the August 12 meeting was pushed back five times, and twice the notice was given the evening before, after the close of business. Other parties noticed the changes in meeting times; see the comments from the Utah Association of Energy Users (UAE) filed on May 25, 2021:[19]

> The delay in completing resource portfolios and the cancellation of the April and May public input meetings provides very little opportunity for stakeholders to provide input and exchange information with the Company in the development of its Action Plan.

In its Reply comments filed with the Commission supporting its application to extend the IRP filing deadline to September 1, the Company stated that the extension would allow it to "continue to facilitate robust and inclusive stakeholder participation that accompanies the portfolio modeling process."[20] That did not happen. In that same filing, the Company indicated that it would present modeling results at the April meeting, and that modeling results would continue to be discussed at the May, June, July, and (if necessary) August meeting dates. However, modeling results were not presented at the April meeting, and not discussed in any detail until the July 30 meeting.

Other parties were unhappy with the Company's IRP process, as evidenced in the following comments in the Oregon IRP docket:[21]

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[18] *NW Energy Coalition's Initial Comments on PacifiCorp's 2021 IRP*, Docket No. LC-77, December 3, 2021, p. 1. See also *Green Energy Institute Initial Comments*, December 6, 2021, pp. 3-4.
[19] https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/2021-irp-comments/2021.080_PacifiCorp-2021_IRP_Feedback_Form_Utah%20Association%20of%20Energy%20Users_5-25-2021.pdf.
[20] *Reply Comments of Rocky Mountain Power on its Request for Extension*, Docket No: 21-035-09, March 10. 2021, p. 4.
[21] *NW Energy Coalition's Initial Comments on PacifiCorp's 2021 IRP*, Oregon Docket No. LC-77, December 3, 2021, pp. 2-3.

> First, the stakeholder review process prior to the IRP filing was erratic and unsatisfactory. Some parts of the process worked as anticipated, for example, review of resource cost inputs and some aspects of the technical analysis. However, the process overall was severely hampered by the inability to review the modeling results until the very end of the time allotted, despite a five-month extension in the filing date.

We understand that a major change in modeling creates process and schedule risk – points we discussed with the Company very early in the process. Were consultation problems for this IRP anomalous, we might be less concerned. But past deficiencies and assurances of IRP process improvement have not borne fruit, and the Division recommends that the Commission be more purposeful in directing the Company to improve and recognizing the limited value of an IRP formed under a deficient process. The multiple instances of postponement, cancellation, and rescheduling, some within only hours of scheduled meetings, substantially decreased effective interaction. By the time modeling results started becoming available, there was almost no time to provide meaningful consultation or review results before the IRP was filed.

Additionally, the Company did not file a Draft IRP. The modeling could not be completed in full before the final IRP filing was made. Several sensitivity runs were not finished at the September 1 filing date; the Company stated in the IRP that it would submit seven of them in a supplemental filing, as shown in Table 9.20 of the IRP.[22] The Division proposes several solutions and recommendations that it has grouped together in the last section of its comments in the subsection "Recommendations."

Draft IRPs

Guideline 5 of the Standards & Guidelines states that "PacifiCorp will submit its IRP for public comment, review and acknowledgement."[23] Guideline 6 goes on to state the following:[24]

> . . .parties will have the opportunity to make formal comment to the Commission on the adequacy of the Plan. The Commission will review the Plan for adherence

[22] 2021 IRP, Vol. I, p. 317.
[23] *Standards and Guidelines*, p. 45.
[24] *Id.*

> to the principles stated herein and will judge the merit and applicability of the public comment. If the Plan needs further work the Commission will return it to the Company with comments and suggestions for change. This process should lead more quickly to the Commission's acknowledgement of an acceptable Integrated Resource Plan. The Company will give an oral presentation of its report to the Commission, and all interested public parties.

In past IRP dockets, the Company filed a draft IRP, and then after a month or more to review parties' comments, filed a final redlined version.[25]

The NW Energy Coalition in Oregon asserts that PacifiCorp did not submit a draft IRP for this cycle, and when coupled with the Company's unsatisfactory stakeholder process, stakeholders lacked sufficient time or a complete set of materials to review and to write comments on.[26] The Oregon Public Utility Commission (OPUC) Staff also expressed concern over the lack of a draft IRP, noting that had one been provided, certain sensitivities could have been requested before filing.[27] The OPUC Staff further commented below (emphasis added):[28]

> According to Guideline 2(c), "[t]he utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission." The preferred portfolio is a key aspect of the IRP and the public should have the opportunity to review and comment on that information prior to the utility filing its IRP. Presentation of that information at a public input meeting prior to filing may technically meet the Guideline, but not the spirit of it. The public is supposed to be allowed "significant involvement" and have an opportunity to make relevant inquiries of the utility. *Provision of this information three business days before filing does not allow for that.*

It is not unreasonable for the Utah Commission to require the Company to provide a draft IRP, as it has previously required in the past. The Company is going to have to provide one going

[25] See, e.g., Docket No: 09-2035-01. The Company filed a draft 2008 IRP on April 8, 2009, and a final redlined version on May 28, 2009. The draft version of Volume I is available at https://pscdocs.utah.gov/electric/09docs/09203501/040809draftIRP.pdf and the redlined final of Volume I is available at https://pscdocs.utah.gov/electric/09docs/09203501/62266IRPRed2008.pdf
[26] *NW Energy Coalition's Initial Comments on PacifiCorp's 2021 IRP*, Docket No. LC-77, December 3, 2021, p. 1.
[27] *OPUC Staff Initial Comments*, Docket No. LC-77, December 3, 2021, p. 33.
[28] *Id.* at 46.

forward to meet its Oregon IRP Guideline 2 requirement. The draft filing provides an additional way for the public to engage with the IRP process and to contribute to the outcome of the final IRP.

The Division points to the Company's dubious claim in this IRP that it effectively filed a draft 2021 IRP (emphasis added):[29]

> Consistent with the Company's previous IRP processes, the public-input meetings, meeting materials reviewed with stakeholders, and consideration of extensive stakeholder feedback forms received throughout the development cycle *is collectively representative of a draft IRP*, discussing inputs, methodology and outcomes and responding and incorporating feedback and comments where applicable.

However, upon even cursory analysis, Company's statement is unpersuasive. These materials do not represent a draft 2021 IRP. Even if the collective feedback of parties over the entirety of the IRP process was robust and in response to an adequate schedule of meetings and review of materials provided in advance, that feedback would be inadequate to constitute a draft IRP. In the face of this IRP process's significant deficiencies, it is even less so. The linked examples from past IRPs (see footnote 25) illustrate that in the past the Company has been able to provide a draft IRP. The Division strongly believes that a draft filing on February 1 would avoid many of the last-minute surprises or the big gap of time when stakeholders are locked out of the IRP process. It would allow stakeholders time to comment on the Company's preferred portfolio and for the Company to go back and make suggested changes where applicable. This is a different exercise than the intermediate feedback provided as the process develops, and is an essential part of what amounts to a peer review process for the IRP.

The Division notes that the Company has already expressed pushback to this suggestion, as noted in its Reply Comments filed in Oregon's IRP docket:[30]

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[29] *PacifiCorp's Reply Comments*, Docket No. LC-77, December 3, 2021, p. 12 (emphasis added).
[30] *Id.* at 12-13.

> The Company asserts that its existing process for meeting the draft IRP requirement is a qualitatively superior and less disruptive process compared to the establishment of a draft document submission. Ongoing and interactive communications with a wide public audience allows the most flexibility throughout and does not require a full stop while drafting requirements are accelerated for drafting, formatting, and review at all levels. The draft-as-document requirement in a four-week timeframe effectively doubles the time required for internal drafting, validation, formatting and review at all levels, as the same exercise must be repeated for the draft and for the final filing. Also, four weeks is not sufficient time for all parties to review and comment meaningfully on a new and comprehensive document while leaving the additional time required for the IRP to assess and integrate additional recommendations for the final filing a short time later. It is far more likely that feedback occurring as part of the ongoing conversation and development cycle, without the distraction of a repeated document creation process, will result in more meaningful input that can be incorporated in the IRP.

Were the Division convinced it would have robust opportunities for ongoing feedback and consultation of the type envisioned by the guidelines, it might have greater sympathy for the Company's argument. However, the continued erosion of opportunities for meaningful consultation and direction by non-Company parties suggests Oregon's draft IRP requirement is wise. Indeed, in this IRP, the Company's own errata and supplemental filings suggest the filing of a draft IRP would provide significant value to the process, enabling greater accuracy.

Public Input and Stakeholder Process: Conclusion

The Company's statements on the stakeholder process do not match the reality of what happened. For example, the IRP stated (emphasis added): "The public has been involved in PacifiCorp's resource plans from the earliest stages and *at each decisive step*."[31] The public was not involved in some decisive steps at all (e.g., the decision to not model new natural gas plants, or the decision to include the Natrium plant). In the IRP, the Company stated:

[31] https://www.pacificorp.com/energy/integrated-resource-plan/public-input-process.html.

> PacifiCorp has pursued an open and collaborative approach involving the commissions, customers and other stakeholders in PacifiCorp's IRP *prior to making resource planning decisions*. Since these decisions can have significant economic and environmental consequences, conducting the IRP with *transparency and full participation* from interested and affected parties is essential.[32]

Again, if the Company "pursued" that approach, it failed to attain it. The Company did not involve the Division prior to making resource planning decisions, the Company was not fully transparent, and stakeholders were not involved in each decisive step. Key company decisions were revealed to others far too late, precluding meaningful changes that might have been made to various processes in developing the IRP. Those decisions have undermined the Division's faith in the ultimate plan the Company filed.

3. IRP Inputs—General Discussion

The IRP relies on a large number of inputs and projections. Many projections extend for the whole period of the IRP (20 years). Some inputs are used to produce different "cases," in order to consider various price assumptions. For example, the Henry Hub natural gas price forecasts in Figure 8.5 of the 2021 IRP (Nominal Wholesale Electricity and Natural Gas Price Scenarios) have three cases: low, medium, and high.[33] The cases represent an effort to establish a medium or base case, plus a range of alternative scenarios where gas prices are higher than expected, or lower than expected.

There are several aspects of the inputs and associated forecasts that the Division would like to point out and identify as concerns. In many cases, part of the projection is based on one method (e.g., a market price), and part of the projection is based on something else (e.g., a third-party forecast). In some cases, the first few years of forecasts are based on market prices, and the "out" years are based on something else; for example, a third-party forecast, or a linear trend.[34]

[32] 2021 IRP Vol. II, p. 83 (emphasis added).
[33] 2021 IRP, Vol. I, p. 228.
[34] What counts as the "out" years may vary by context. The action plan of the IRP describes resource actions that the company will take over the next two to four years of the 20-year IRP window, so in general, years 5-20 of the forecast count as "out" years.

For example, the official forward price curve (OFPC) for electricity prices uses "market forwards, followed by a market-to-fundamentals blending period that transitions to a pure fundamentals-based forecast."[35] This is necessary since market data is not available for all of the IRP years. This can be complicated because sometimes the Company's projections differ, sometimes substantially, from those of other entities that make projections.

This difference is to be expected, and the Division is not criticizing the Company's methods, as there are many methods used for projections. Rather, the Division points out that there are many reasonable projections, and they can differ quite a bit, especially in the out years. Therefore, caution should be used in the "out" years when basing costly resource decisions on projections. Different projections lead to different conclusions, and therefore any given conclusion may be just one of many reasonable conclusions. Small changes in the methods could result in large changes in the resources chosen in the out years. We discuss this further in Section 7 below.

4. The Natrium Plant

The 2021 IRP includes the Natrium advanced nuclear demonstration project (Natrium plant) in the resources available for selection by the model. The Natrium plant is a nuclear reactor that uses molten sodium as a coolant.[36] The Natrium plant will have a molten salt thermal energy storage tank on site. The reactor itself will produce a maximum of 345 MW, and with the storage the maximum output of the site will be 500 MW. This maximum output of 500 MW will be sustainable for 5.5 hours, after which time the storage will be depleted and the maximum output will be the 345 MW of the reactor.[37]

At the time of the IRP, the proposed site for the plant had not been selected, although for modeling purposes, it was assumed to be built near the site of the Naughton coal plant.[38] Since

[35] 2021 IRP, Volume 1, p. 227. For electricity process, the first 36 months of the OFPC are a snapshot of market prices (at the time of the writing of the IRP). Next, "[t]he blending period (months 37 through 48) is calculated by averaging the month-on-month market forward from the prior year with the month-on-month fundamentals-based price from the subsequent year." Finally, the "fundamentals portion of the electricity OFPC reflects prices as forecast by AURORAXMP (Aurora), a WECC-wide market model." *Id*.

[36] 2021 IRP Volume I, p. 204. "Natrium" is a registered trademark.

[37] *Id*.

[38] *Id*. at 5.

the IRP was issued, TerraPower confirmed that the Natrium plant would be sited in Kemmerer, Wyoming, near the Naughton coal plant.[39]

The Division believes that the Natrium plant should not have been included in the base case modeling. The inputs for the Natrium plant used in the model, such as price and expected completion date, are too uncertain. The Division is in favor of exploring the Natrium plant as part of a least-cost/least-risk strategy; however, at this time the costs and risks are too volatile to be properly modeled. The Division does not object to the Natrium plant being modeled in sensitivity scenarios, but the preferred portfolio should not include the Natrium plant until cost and timing issues are known with more detail. The Division's conclusion is based on the following factors:

- The Natrium plant uses molten sodium as the moderator and the coolant. This type of nuclear plant has never been used for commercial power in the U.S., and therefore costs are even more uncertain than those of "typical" U.S. nuclear plants.[40]
- The last few nuclear plants built in the U.S. have had significant cost overruns.
- The Company does not yet have contracts in place to establish the base cost of the plant or to describe how possible cost overruns will be handled.
- The fuel for the Natrium plant does not have an established supply chain in the United States. The Company does not yet have fuel supply contracts in place.

These reasons are discussed in more detail below. For these reasons, it is premature to include the Natrium plant in the preferred portfolio. As the project develops and contracts are made between the Company and TerraPower and other entities regarding cost overruns and fuel supply issues, the Natrium plant may be appropriate to be included in the preferred portfolio. A brief discussion of the technology used for the Natrium plant will illustrate the reasons for the Division's concerns.

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[39] *TerraPower selects Kemmerer, Wyoming as the preferred site for advanced reactor demonstration plant*, November 16, 2021, at: https://www.terrapower.com/natrium-demo-kemmerer-wyoming/

[40] There have been a few sodium-cooled fast reactors built elsewhere in the world; e.g. the Superphénix in France. See https://en.wikipedia.org/wiki/Superphenix

The Natrium Plant Technology Has Never Been Used for Commercial Power in The U.S.

At a high level, most nuclear power plants are similar to other thermal plants such as coal or natural gas—heat is generated, the heat boils water, and the water (or steam) drives a turbine generator. The heat in nuclear reactors is released by fission, which is a chain reaction whereby neutrons cause uranium to split into other elements.[41] When the uranium splits, it releases more neutrons, which continues the chain reaction with other uranium atoms.

Some nuclear reactors require a "moderator," which is a substance that slows neutrons down. Generally speaking, with some nuclear fuel, "faster" neutrons are not as efficient at continuing the chain reaction—the moderator "slows" the fast neutrons so that they become "thermal" neutrons, which then continue the chain reaction.[42] Therefore, some nuclear reactors need a moderator (which slows down the neutrons) in addition to a coolant (which all commercial plants need, and which transfers heat to the turbine).[43]

It is the Division's understanding that in all currently operating commercial power nuclear reactors in the U.S., water serves as both the moderator and the coolant. All currently operating nuclear reactors used for power generation in the United States are either "pressurized water reactors" (PWRs), or "boiling water reactors" (BWRs).[44]

In a BWR, the nuclear reaction causes the water (which is serving as both moderator and coolant) to boil and turn into steam. The steam drives a turbine, condenses back into water, and then travels back to the reactor core. There is only one "loop" of water that transfers heat to the turbines in a BWR.[45]

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[41] Fission can be caused by particles other than neutrons and can use starting materials other than uranium (e.g. plutonium), but for purposes of this discussion, fission can be thought of as a chain reaction of uranium atoms being split by bombardment with neutrons.

[42] See the following for more discussion of the role of a moderator: https://en.wikipedia.org/wiki/Neutron_moderator and http://large.stanford.edu/courses/2017/ph241/barry2/

[43] See http://large.stanford.edu/courses/2011/ph241/omar1/ for an overview of coolants.

[44] See the Nuclear Regulatory Commission's "List of Power Reactor Units" at https://www.nrc.gov/reactors/operating/list-power-reactor-units.html

[45] See https://www.nrc.gov/reactors/bwrs.html for a brief overview of BWRs.

In PWRs, the concept is similar, but there is a second water loop used to transfer heat to the turbines. In the first water loop in a PWR, water is heated by the reactor so that it becomes heated (pressure in the loop prevents the water from boiling). This pressurized loop of super-heated water then heats water in a second self-contained loop via a heat exchanger. Steam is produced in this second loop and drives the turbine generator.[46]

Since all currently operating commercial power nuclear reactors in the U.S. are either PWRs or BWRs, the safety and construction issues with these plants are fairly well known. The BWR/PWR technology is mature.

The Natrium Plant Uses a Technology Never Used in the U.S. For Commercial Power

In contrast, the technology to be used at the Natrium plant is untested in the United States for commercial power production. The Natrium plant uses liquid sodium for its coolant.[47] As this design is untested, there may be delays in Nuclear Regulatory Commission (NRC) approval and construction. There are safety issues present with sodium reactors that are not present with BWRs and PWRs.[48] The Division's concern here is not to debate the safety of the design, rather it is to point out that a new design with heretofore unregulated safety issues may experience delays in approval and cost overruns. As an example of how costs at nuclear plants can experience overruns, the Division will briefly discuss below the last two commercial nuclear plants built in the U.S.

[46] See https://www.nrc.gov/reactors/pwrs.html for a brief overview of PWRs.

[47] As the Natrium plant is a "fast" reactor, meaning it uses faster neutrons for fission, and so the moderating effect of water (as in PWR and BWR designs) is not needed.

[48] Conversely, there are safety issues present with PWRs and BWRs that are not present with sodium-cooled reactors. To see a brief discussion of sodium-cooled reactor safety issues, see: Can Sodium Save Nuclear Power? Scientific American, October 13, 2014 https://www.scientificamerican.com/article/can-sodium-save-nuclear-power/

Recent Nuclear Projects Have Been Costly and Delayed

The last few commercial nuclear plants built in the United States have poor track records regarding cost and delays. Georgia Power is close to finishing Vogtle units 3 and 4 in Waynesboro, Georgia. These units are both PWRs that use the Westinghouse AP1000 design. Georgia Power projects a Unit 3 in-service date Q3 of 2022 and a Unit 4 in-service date in 2Q of 2023.[49] Estimates of the cost overruns at Vogtle vary, but most estimates indicate that the plant has cost at least double the original projections:

> [T]he total cost of Vogtle has now more than doubled the original projection of $14 billion. … Total costs are actually higher than $28.5 billion, because that doesn't count the $3.68 billion that contractor Westinghouse paid back to owners after going bankrupt. When approved in 2012, the first electricity was supposed to be generated in 2016.[50]

Thus, the Vogtle plant came in well over double the original cost and will be at least six years late. Furthermore, this plant used PWR technology, which has a long track record in the U.S. It is reasonable to be wary of cost overruns with the Natrium plant, which is a technology untested in the U.S.

The other nuclear project started in the last decade was Units 2 and 3 at V. C. Summer power station (Summer) in South Carolina. There is one Westinghouse PWR reactor already operating at Summer, and there were plans by South Carolina Electric & Gas (SCEG) to expand the station and build two more Westinghouse AP1000 reactors. The original cost of the reactors when the contract was signed between SCEG and Westinghouse was to be $9.8 billion, with Unit 2 to come online in 2016, and Unit 3 to come online in 2019.[51] After numerous delays and cost

[49] *Plant Vogtle Units 3 and 4*, Southern Company, at https://www.southerncompany.com/innovation/vogtle-3-and-4.html Georgia Power is owned and operated by Southern Company.
[50] *'Outrageous' price tag: Plant Vogtle cost doubles to $28.5 billion as other owners balk*, Jeff Amy, Nov. 4, 2021, The Augusta Chronicle, available at https://www.augustachronicle.com/story/news/2021/11/04/georgia-power-nuclear-reactors-plant-vogtle-cost-doubles-energy-costs/6286729001/
[51] *The failed V.C. Summer nuclear project: A timeline*, Choose Energy, December 4, 2018, at https://www.chooseenergy.com/news/article/failed-v-c-summer-nuclear-project-timeline/ See also *Virgil C. Summer Nuclear Generating Station*, at https://en.wikipedia.org/wiki/Virgil_C._Summer_Nuclear_Generating_Station

overruns, the project was abandoned in 2017. One estimate stated that completing construction could have cost more than $23 billion, or an overrun of $13.2 billion. South Carolina taxpayers ended up paying billions for a project that never produced a kilowatt of electricity.

Before the Vogtle and Summer plants, the last nuclear reactor to come online in the U.S. was Watts Bar Unit 2, which came online in 2015. Watts Bar Unit 2 is the only reactor to come online since 1995.[52] Watts Bar Unit 2 was also a PWR built by Westinghouse. It is difficult to determine the exact amount of cost overruns for Watts Bar Units 1 and 2, because construction began in 1975, with Unit 2 being delayed in the 1980s due to flat-lining demand. One estimate had the original cost of the plant at $400 million, with final total costs over $6.1 billion.[53] Watts Bar Units 2 is a special case, as it was planned in the 1970s, and put on hold when national demand slowed. However, the fact remains that the last three plants to come online in the U.S. have had huge cost overruns. Until a mechanism is in place to put a cap on possible cost overruns, the Natrium plant should not be part of the preferred portfolio.

The Natrium Plant Has Cost and Delay Risks That Are Not Apparent for Other Resource Types

The Company and TerraPower are of course not destined to repeat the mistakes of the Vogtle and Summer plants. Those projects were had management issues, and Westinghouse, the company building the plants, went bankrupt in 2017. The Company will point out, rightly, that its proposed plant is a completely different design, and of a smaller scale.

However, since the design is new for U.S. power production, there may still be delays and cost issues. Any cost overruns at the Natrium plant are likely to be of a different kind than those at other types of resources, such as gas, wind, and solar facilities. As we have seen during COVID, supply chain disruptions for any type of plant can cause delay, cost overruns, and shortages related to raw materials, manufactured materials, computer chips, and manpower. However,

[52] *Watts Bar Nuclear Plant,* at https://en.wikipedia.org/wiki/Watts_Bar_Nuclear_Plant
[53] *America's first '21st century nuclear plant' already has been shut down for repairs*, Los Angeles Times, May 8, 2017, at: https://www.latimes.com/business/hiltzik/la-fi-hiltzik-nuclear-shutdown-20170508-story.html

nuclear projects are subject to all of the same types of delays and cost overruns, plus delays in federal permitting, fuel sourcing, and design.

The Division does not mean to imply that the Natrium plant is doomed to large cost overruns and delays. The Division supports exploration of new technologies, including nuclear. However, the Company must be prepared for possible overruns. The sodium-cooled type of reactor is new to commercial power operation in the U.S., and tweaks in the design and construction are likely. To avoid a situation where ratepayers are on the hook for large overrun and delay costs, the Company needs to have contracts in place specifying how these issues are to be addressed. Until those contracts are in place, the Natrium plant should not be modeled as a resource similar to other resources—the cost, timing, and risk parameters are not well known well.

The Company Needs to Explain How Cost Overruns Are Handled Before Putting Nuclear in the Preferred Portfolio

The Standard and Guidelines state the following:

> PacifiCorp's future integrated resource plans will include: … An evaluation of the financial, competitive, reliability, and operational risks associated with various resource options and how the action plan addresses these risks in the context of both the Business Plan and the 20-year Integrated Resource Plan. The Company will identify who should bear such risk, the ratepayer or the stockholder.[54]

The Division asked about cost overruns in a Data Request, as follows:

> Please explain how cost overruns will be handled with the Natrium Project. Is there a maximum overrun that the Company would accept before the project is cancelled? Is there a maximum amount of cost overruns that the Company would attempt to recover from ratepayers? Please provide a copy of any contracts (with TerraPower or any entity associated with the Natrium Project) that relate to costs, overruns, possible project delays, and possible project termination.

The Company's response stated:

[54] *Report and Order on Standards and Guidelines*, Docket No. 90-2035-01, June 18, 1992 (Standards and Guidelines), Guideline 4(h), p. 44.

> PacifiCorp has not signed any contractual agreements with TerraPower LLC regarding the Natrium™ nuclear reactor demonstration project. Any future contract agreements will ensure risk and costs are minimized for PacifiCorp customers.[55]

This response is not sufficient for a nuclear plant, given their recent history. Before a nuclear plant can be included in the preferred portfolio, the contracts should be in place, so that stakeholders can evaluate them. As noted at the beginning of this report, the current IRP was delayed by the Company in order to allow the results of the 2020 All-Source Request for Proposals (2020AS RFP) to be included in the current IRP planning cycle. One reason given for the delay was that the updated prices from the RFP process could serve as inputs into the IRP modeling. In contrast, the cost inputs for the Natrium plant are speculative and no contract is in place to detail the maximum cost ratepayers would be expected to pay (or if such a maximum will be in place). A vague notion that risks for customers will be "minimized" is not sufficient. In an interview, Mr. Rick Link, PacifiCorp's Vice President of resource planning, stated "TerraPower has stated publicly that it will ultimately assume the risk of cost overruns, schedule delays and performance, protecting PacifiCorp customers."[56] Once this assumption of risk is put into a binding agreement, the Division may be able to support nuclear power in the modeling for the preferred portfolio. Until then, nuclear power should remain in sensitivity cases only.[57]

The Fuel to Be Used By the Natrium Plant Is Not Currently Manufactured in the United States

In addition to the untested design, the Natrium plant will use fuel that is not currently readily available in the U.S. Obviously, the plant would not go forward if the Company cannot secure a

[55] *Rocky Mountain Power's Responses to DPU 4th Set Data Requests 4.1-4.6*, Docket No. 21-035-09, Response to DPU Data Request 4.4, January 20, 2022.

[56] *Oregon groups wary of PacifiCorp's nuke plan with Bill Gates' TerraPower*, Portland Business Journal Feb 8, 2022. Available at https://www.bizjournals.com/portland/news/2022/02/08/oregon-groups-not-sold-on-pacificorps-nuclear-plan.html

[57] The difference between the Company's view of risks associated with various plant types is quite striking. With vaguely-sourced numbers and myriad risks evident in nearly every available example, the Company concluded a nuclear plant could be and should be modeled for the IRP. It also included a hypothetical proxy hydrogen resource whose technological maturity is nascent, at best. In contrast, the Company concluded that natural gas plants, with a long track record of building and operation in low-cost and low-risk portfolios, should not be modeled.

long-term fuel contract, but a brief discussion of the fuel that the Natrium plant will use can illuminate some of the supply-chain risks.

Most nuclear reactors use uranium as their fissile materials (i.e., their fuel source).[58] The fissile material that is most commonly used in the U.S. for nuclear fuel is U235, an isotope of uranium. Uranium found in nature contains mostly the isotopes U238 (99.3%) and U235 (0.7%), with only traces of other isotopes.[59] To make nuclear fuel from uranium, the percentage of U235 is increased from the naturally occurring 0.7% concentration to 3% or more. Increasing the percentage of U235 is "enrichment" of the uranium. The percentage amount (e.g., "4% enriched uranium") always refers to the percentage of U235 in the material, as opposed to U238.

There are two main categories of uranium nuclear fuel, depending on the U235 percentage:

- Highly enriched uranium (HEU) (20%+ U235); and
- Low enriched uranium (LEU) (more U235 than the naturally occurring 0.7%, but under 20% U235).

HEU can be used for reactors but is also used for nuclear weapons. Nuclear weapons typically use uranium that is 85% or higher U235 (weapons-grade), but a bomb could possibly be made from uranium in the 20%-85% range. Therefore, the rules and regulations for handling HEU are very strict.

Most U.S. reactors currently producing commercial power use fuel that is under 5% enrichment of U235.[60] These reactors are all light water reactors (ordinary water is used as a coolant and as a moderator)—either PWR or BWR designs. The Natrium plant proposes to use high-assay low-enriched uranium (HALEU), which is a subcategory of LEU where the U235 is in the 10% to

[58] Nuclear reactors can also use other fissile materials for fuel, such as plutonium or thorium, but this is not common for commercial power reactors.
[59] Most of the following three paragraphs can be found in *Uranium Enrichment*, World Nuclear Association, at http://www.world-nuclear.org/information-library/nuclear-fuel-cycle/conversion-enrichment-and-fabrication/uranium-enrichment.aspx See also https://en.wikipedia.org/wiki/Nuclear_fuel
[60] See *Nuclear Fuel*, Argonne National Lab, https://www.ne.anl.gov/pdfs/nuclear/nuclear_fuel_yacout.pdf ("Typically UO2 fuel is enriched in the fissile isotope U-235 to about 3-5% (U-235 fraction in natural uranium is about 0.7%)…")

20% range—still LEU, but on the higher end.[61] HALEU has higher safety and anti-terrorist precautions than the 3-5% fuel used by all other commercial U.S. power plants.

HALEU is currently not produced in the U.S. on a commercial power scale. If the Natrium plant goes forward, the Company plans to obtain HALEU fuel from Centrus Energy (Centrus):[62]

> Centrus is currently working under a three-year, USD [$]115 million cost-shared contract with the DOE to deploy 16 of its AC-100M centrifuges at its Piketon, Ohio, facility to demonstrate HALEU production. Once the demonstration is complete in mid-2022, TerraPower would work with Centrus to expand the plant to meet the fuel requirements of the Natrium demonstration reactor.

The Division's understanding is that no contracts are yet in place between the Company and Centrus. Until this contract in place, the risks regarding fuel supply side of the Natrium plant are much higher than risks for coal, natural gas, or renewable supply chain equipment. Until that fuel supply contract is in place, the Natrium plant should not be part of the preferred portfolio—the plant should be modeled as an alternative.

5. Coal Retirements

Reducing the amount of coal generation has been a trend in recent IRPs, for both financial and environmental reasons. The 2019 IRP introduced certain accelerated coal unit retirement dates derived from an economic study[63] that the Company performed on each of its coal units. The analysis considered a wide range of retirement dates and system variables from which it ultimately identified some portfolio optimization for the demands of carbon-neutral electricity. Ultimately the coal studies showed benefit from retiring certain coal resources early and replacing them with lower cost energy resources like wind, solar, and storage. Beyond lessening carbon emissions, demonstrated benefits also include the reduction of cost and risk on

[61] Some sources define HALEU as 5% to 20% enrichment, instead of 10% to 20%.
[62] *TerraPower and Centrus team up for HALEU production*, World Nuclear News, September 16, 2020, available at: https://www.world-nuclear-news.org/Articles/TerraPower-and-Centrus-team-up-for-HALEU-productio
[63] Docket No. 19-035-02, PacifiCorp 2019 IRP (2019 IRP), October 18, 2019, Volume II, Appendix R, p. 591.

PacifiCorp's system. However, it is important to note that these early coal retirements were implemented when they were cost-effective and when they were part of a least-cost/least-risk strategy—this was the whole point of the coal studies done in the 2019 IRP.

The coal studies were prompted in part by legislation passed in the state of Oregon in 2016 that prohibits utilities from including coal plants in their rates beyond 2030.[64] The State of Washington enacted the Clean Energy Transformation Act (CETA) in 2019 to transition 100% to a clean energy supply by 2045.[65] Both the Oregon and Washington acts are state-specific and are constraints on the Company's six-state system planning structure.

In the near-term four-year action plan, the 2021 IRP Preferred Portfolio consists of a strategy to retire, or convert to natural gas, 7 of the Company's 22 coal units. The long-term action plan includes retirement or conversion of 14 of the Company's 22 coal units by 2030 and 19 of the Company's 22 coal units by the end of the 2040 planning period.[66] Meanwhile, the action plan will add lower-cost renewable energy resources like wind and solar. The projected difference in capacity between renewable generation and thermal generation has never been greater in any of PacifiCorp's sixteen IRPs filed with the Public Service Commission of Utah than in this 2021 IRP. Historically, coal has dominated the Company's generation portfolio as the largest resource. Currently coal accounts for 49 percent of PacifiCorp's system energy generation. Before the end of the near-term action plan period in 2025, coal generation will drop to 29 percent. The long-term action plan will further reduce coal generation to 15 percent by 2030, and to 1 percent by the end of the 2040 planning period.[67]

[64] Oregon Clean Electricity & Coal Transition Plan (S.B. 1547B), signed into law on March 8, 2016. S.B. 1547B, requires the state's major investor-owned electric utilities to largely eliminate the use of coal generation by Jan. 1, 2030, and obtain 50% of power sold to retail customers from renewable energy by 2040. In addition to renewables, the law contains provisions for energy storage and transportation electrification. See: https://olis.oregonlegislature.gov/liz/2016R1/Measures/Overview/SB1547
[65] On May 7, 2019, Senate Bill 5116 was enacted in Washington, establishing a coal elimination standard, a greenhouse gas neutral standard and a 100% renewable and non-emitting portfolio standard. See: http://lawfilesext.leg.wa.gov/biennium/2019-20/Pdf/Bills/Session%20Laws/Senate/5116-S2.SL.pdf?q=20200127192903 (Section updated 8/12/19).
[66] 2021 IRP, Vol. I, p. 15.
[67] *Id.* at 304.

The Division believes coal retirements will contribute positively to climate, environmental, and human health. However, the Company should not pursue low emissions as its fundamental objective; its fundamental planning objective is finding the mix of least-cost, least-risk resources. Emission costs and risks are relevant components in that objective, but they are not the objective. The Division has concerns and is not persuaded that the 2021 IRP strictly adheres to its primary objective to identify the best mix of resources in least-risk, least-cost planning. An over-emphasis on thermal plant retirements, and a refusal to even model new thermal plants, is concerning to the Division and suggests that, at least in part, some state energy choices[68] are driving portfolio decisions across the system. A faster-than-optimal departure from thermal resources and refusal to consider additional new natural gas resources could increase uncertainties and risk. We discuss this move away from new natural gas resources in the next section.

6. The Decision Not to Model New Natural Gas

In the 2021 IRP, "new natural gas proxy resources were not made available for selection in any of [the] Initial Portfolios."[69] This decision was not made public at the beginning of the IRP process; the first announcement of it was on June 25, 2021, in the IRP meeting materials. During a public input meeting, on July 30, 2021, the reasons given for not modeling new natural gas plants in the Initial Portfolios were as follows:

> There are considerable stranded-cost risks associated with planning a system that is reliant on new natural gas resources with depreciable lives ranging between 30 to 40 years (i.e., a new gas-fired resource placed in service in 2030 would be depreciated as late as 2070). Further, when considering current state policies, it is not feasible to assume new natural gas resources can obtain the permits needed to site and operate such a facility in many parts of PacifiCorp's service territory. Finally, PacifiCorp has observed that there is very limited development activity

[68] The Division suspects that the states' underlying resource views are not as different as they may seem. Indeed, all states share a vision of a future portfolio comprising lower emissions and sustainable resources. Generally, most agree on the direction of the resource mix, and state policies on the matter tend to differ most in the pace of change. This is an important point because the IRP should tell us more than this one does about the expected pace of change, factors that affect that change, and consequences of headwinds on the path to that change. It is harder to accomplish these objectives when entire proven resource types are excluded from any consideration.

[69] *Id.* at 245.

> for new natural gas facilities. This was most recently evident in the 2020AS RFP, which did not result in a single bid for new natural gas resources.[70]

The Division does not agree with this decision, for the following reasons:

- The decision to not model natural gas resources was announced to stakeholders toward the end of the IRP cycle: June 25, 2021, well after the IRP was originally due. If the decision was made earlier, it was not announced to stakeholders.
- The decision appears to be driven in part by state policies, such as Washington's CETA, that should not govern initial resource modeling decisions, even if they must be considered.
- The Company did not attempt to quantify the stranded-costs risks.
- No discussion was given of what permits could hinder the construction of new natural gas peaker plants—e.g., does this refer to local, state, or federal permits? If state permits, which states?
- The peaker plants that the Company did use in its Initial Portfolio modeling were an unnamed proxy peaker plant (possibly hydrogen).

These reasons are discussed in more detail in the following subsections.

The Company's Reasoning for Not Modeling New Gas Resources

In the slides for the July 30, 2021 public input meeting, the Company gave its reasoning for why new natural gas plants were not being considered, and stated that "non-emitting peaking units" would replace the natural gas units:

- Net load data shows a low-capacity factor, long-duration resource option is needed – ideally with a low fixed cost per kW. Cost per MWh is less important, because it will operate infrequently.
- Traditionally, this role was filled by a Natural Gas-Fired Frame Simple Cycle Combustion Turbine (SCCT), but the core cases are not considering new natural gas-fired resources.

[70] *Id*.

- A variety of suitable technology options are under development: including hydrogen, ammonia, and long-duration storage of various types.
- As a proxy for this future technology (assumed available in 2030), PacifiCorp developed costs and performance data for a 100% hydrogen-fired Frame SCCT. While this is not mature technology, major turbine manufacturers plan to deploy this in the next few years.[71]

In its Data Request 5.1(b), the Division asked about the Company's reference to the feasibility of obtaining permits for gas plants.[72] The Company stated that it was not aware of any federal policy that would expressly preclude new gas sources, although the Regional Haze rule would need to be followed. The Company also referred to its answer for Division Data Request 5.2, which asked for a list of state requirements that informed the "no gas" decision. The Company answered as follows:

> As discussed at the 2021 IRP public input meetings held on June 25, 2021 and July 30, 2021, considering the potential for future greenhouse gas (GHG) policies, PacifiCorp noted there are considerable stranded-cost risks associated with planning a system that is reliant on new natural gas resources with depreciable lives ranging between 30 to 40 years (i.e., a new natural gas-fired resource placed in service in 2030 would be depreciated as late as 2070). Further, when considering current state policies, it is not feasible to assume new natural gas resources can obtain the permits needed to site and operate such a facility in parts of PacifiCorp's service territory. Washington and Oregon legislation currently include provisions to meet all retail customer load requirements with non-emitting energy in the future, which explicitly limits the useful life and potential of new natural gas resources to significantly less than 30 years. In addition, it is not

[71] 2021 IRP Public-Input Meeting July 30, 2021, slide 18, available at https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/PacifiCorp%202021%20IRP_PIM_July_30_%202021.pdf

[72] The text of the question was:

> The Company has chosen not to exclude natural gas resources as proxy resource selections (see, e.g., IRP Chapter 8, p. 245). The Company states that "it is not feasible to assume new natural gas resources can obtain the permits needed to site and operate such a facility in many parts of PacifiCorp's service territory."
> (a) Is this statement referring to federal, state or both federal and state permitting assumptions?
> (b) Please list and describe all federal policy or federal permitting regulations used to justify the Company's "no gas" decision. Please provide all sources.
> (c) Please list and describe each respective state policy and/or state permitting regulations used to justify the Company's "no gas" decision. Please provide all sources.

> envisioned that new natural gas resources could be economically permitted in northern Utah due to state implementation plans (SIP) for the counties of Salt Lake, Davis and Box Elder regarding particulate matter (PM) of 2.5 microns or less. There would also be challenges complying with the state SIPs regulating ozone (O) and nitrogen oxides (NOx). Finally, PacifiCorp has observed that there is very limited development activity for new natural gas facilities. This was most recently evident in the Company's 2020 All Source Request for Proposals (2020AS RFP) which did not result in a single bid for new natural gas resources. Nonetheless, PacifiCorp produced a sensitivity in the 2021 IRP that allowed new natural gas proxy resources.[73]

The Division has concerns about aspects of the Company's answers. To begin with, the Commission's Standards and Guidelines 4(b)(ii) as put forth in its Order in Docket 90-2035-01:

> PacifiCorp's future integrated resource plans will include: … [a]n assessment of all technically feasible generating technologies including: renewable resources, cogeneration, power purchases from other sources, and the construction of thermal resources.[74]

The Division understands why the Company does not include new coal plants in its modeling—the issue of uneconomical coal plants was discussed extensively in the previous two IRPs and was the subject of a detailed coal study in the 2019 IRP. Furthermore, new coal plants are not being built in this country. However, the decision to not model new natural gas plants (which, unlike new coal plants, are still being built in the country) was made in the middle of the IRP cycle, with only a few paragraphs of explanation.

The Decision Was Made Late in the IRP Cycle

The first that stakeholders heard about the decision not to model new natural gas was on June 25, 2021. Before that, the Company had listed natural gas plants in its supply-side resource table

[73] *Rocky Mountain Power's Responses to DPU 5th Set Data Requests 5.1-5.6*, Docket No. 21-035-09, January 26, 2022, Response to DPU Data Request 5.1.
[74] *Standards and Guidelines*, p. 43

(issued on January 11, 2020).[75] The presentation for June 25, 2021, on the slide describing Portfolio Development Cases, stated in a footnote that the new proxy resources column "Excludes new gas proxy resources not including options for gas conversion of specific existing resources that will be optimized."[76] The Division's understanding is that this was the first time that the Company told stakeholders that new natural gas plants would not be modeled; stakeholders were told well after portfolio modeling was underway.

This decision was announced to stakeholders too late in the process—after a supply-side resource table was produced, and after modeling was begun.

The Stranded Asset Risk Should Be Detailed and Quantified

The Company is not clear regarding the exact nature of the stranded asset risk. Presumably, the Company is referring to the possibility of a carbon tax, or possibly other factors, such as state policies, societal pressure, or the development of non-emitting peaker technology. The Division sees no reason why these risks cannot be quantified using (for example) a carbon tax forecast and other quantitative inputs. The Company has acknowledged that a peaker plant like this would have "very infrequent" use,[77] thus a carbon tax would not have as much cost as it would for a baseload or intermediate resource. The Division requests more analysis and details regarding the exact nature of the risk and quantification of the decision.

The Proxy Plants Used in Modeling Do Not Yet Exist in a Mature Form

As the Company stated in its slide referenced above, the peaker plant technology used in the IRP modeling was a hydrogen-fired SCCT, which is not a mature technology. Thus, the Company is replacing a proven technology with costs that are fairly well-known (natural gas) with a nascent

[75] See Supply-Side Resource Table, available at https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-1-11%20Supply-Side%20Resource%20Table.pdf
[76] 2021 IRP Public-Input Meeting June 25, 2021, slides 45 and 46, available at: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/PacifiCorps_2021_IRP_PIM_June_25_2021.pdf
[77] Integrated Resource Plan 2021 IRP Public-Input Meeting, July 30, 2021, slide 6, available at: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/PacifiCorp%202021%20IRP_PIM_July_30_%202021.pdf

technology with costs that are not known with any level of certainty. The Division does not object to the possibility of new technology, especially in the out years, but it does object to the removal of new natural gas resources from the modeling.

The Company has not followed Guideline 4(i) of the Standards and Guidelines, which states as follows:

> PacifiCorp's future integrated resource plans will include: … Considerations permitting flexibility in the planning process so that the Company can take advantage of opportunities and can prevent the premature foreclosure of options.[78]

The Company has prematurely foreclosed the option of natural gas peaker plants. If the hydrogen peaker plant or other non-emitting peaker technology does not advance as planned, the natural gas peaker plant option may be needed. This point is key because the IRP is not simply an exercise about finding the least cost, least risk portfolio. The IRP is also not a Company-only process, because stakeholder evaluation and input is critical. Rather, the IRP is a process designed to illuminate the full spectrum of resource choices in a way that allows a utility to make a near-term action plan, identify a longer-term preferred portfolio, and also to learn enough about various portfolios to have a disciplined sense of options and risks if circumstances necessitate a deviation from the preferred portfolio. This last point is especially important if the preferred portfolio includes such unknown resources as the Natrium plant, or other as yet unproven technology. An IRP should help answer the question of what options the Company will have to meet demand if significant resources in its plan, new or existing, become unavailable. For that reason, modeling should include proven resources and new technologies, while being candid about their limitations.

The Decision Was Partially Driven by State Policies; the Permit Difficulties Are Not Well-Founded

The Company states that "Washington and Oregon legislation currently include provisions to meet all retail customer load requirements with non-emitting energy in the future, which

[78] *Standards and Guidelines*, p. 44.

explicitly limits the useful life and potential of new natural gas resources to significantly less than 30 years."[79] This appears to be a case of state rules dictating what inputs and resources should be modeled in the IRP for the entirety of the system, contrary to assurances made in other forums.

The Company notes that "it is not envisioned that new natural gas resources could be economically permitted in northern Utah due to state implementation plans (SIP) for the counties of Salt Lake, Davis and Box Elder regarding particulate matter (PM) of 2.5 microns or less."[80] This does not mean that new peaker plants could not be built in other counties in Utah, or in Wyoming.

Although construction of gas plants in the U.S. has slowed, it has certainly not stopped. The U.S. Energy Information Administration (EIA) states that "[b]etween 2022 and 2025, 27.3 gigawatts (GW) of new natural gas-fired capacity is scheduled to come online in the United States."[81] The map of locations is shown below.

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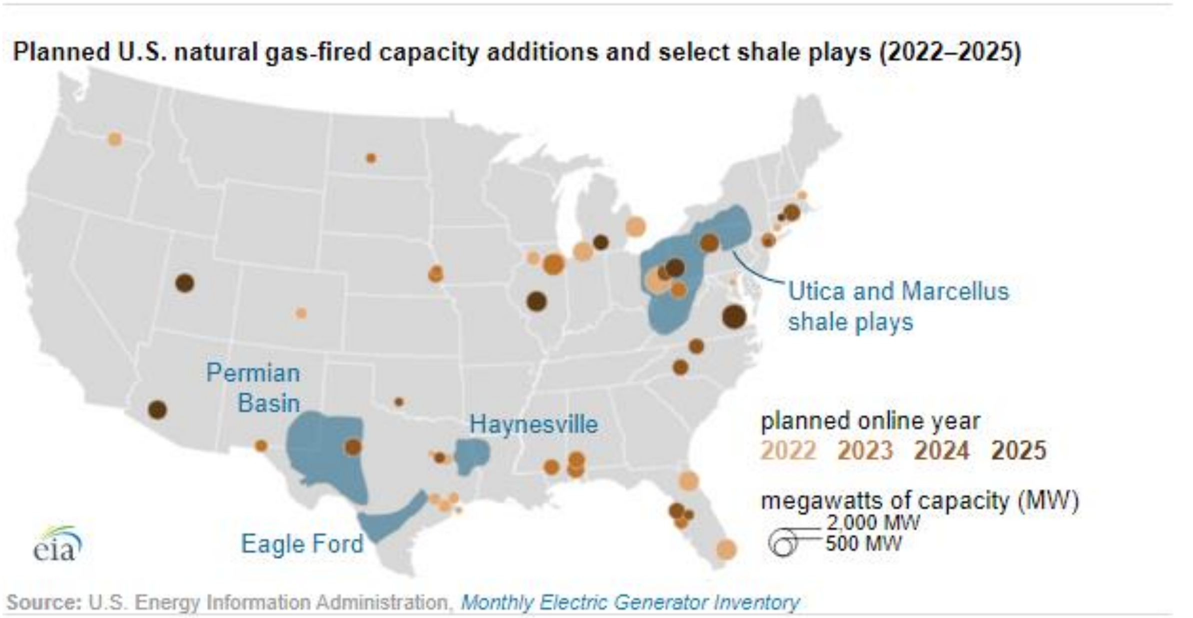
[79] *Rocky Mountain Power's Responses to DPU 5th Set Data Requests 5.1-5.6*, Docket No. 21-035-09, Response to DPU Data Request 5.2, January 26, 2022.
[80] *Rocky Mountain Power's Responses to DPU 5th Set Data Requests 5.1-5.6*, Docket No. 21-035-09, January 26, 2022, Response to DPU Data Request 5.1.
[81] *Most planned U.S. natural gas-fired plants are near Appalachia and in Florida and Texas*, EIA, November 22, 2021, available at https://www.eia.gov/todayinenergy/detail.php?id=50436

Figure 1 EIA Planned New Gas Plants



The plant in Utah in the above figure is a planned conversion of two coal units by Los Angeles Dept. of Power and Water (LADWP) at the Intermountain Power Project in Delta, Utah. The LADWP plans to put a natural gas combined cycle at the site in 2025 and start a transition to a natural gas/hydrogen mix in 2035, with a switch to pure hydrogen by 2045.

Other utilities in Utah are planning new gas peaker plants. For example, Deseret Power in Utah recently received approval of a Certificate of Public Convenience and Necessity (CPCN) from the Commission for a new gas peaker plant, with a probable location of St. George, Utah.[82] The Division recognizes that a gas plant built by the Company would be hundreds of megawatts in capacity (as opposed to the 15 MW of peaking sought by Deseret Power), and would have much more onerous permitting. However, the fact is that new gas plants are still being built around the country, and the Company should include them in its preferred portfolio modeling.

The Company's procedure for producing the IRP should have been:

[82] *Report and Order*, Docket No. 21-0506-02, February 3, 2022.

> (1) Run the modeling for least-cost/least risk, using "all technically feasible generating technologies," then
>
> (2) Discuss state processes, permits, risks, etc., and use risk and cost quantification to modify any portfolios as needed, and then assign any changes in costs in the least cost/least risk portfolio to the state policies that caused them.

The Division also notes that the difficulty of getting state permits in Utah and Wyoming is likely far less than the difficulty of getting the federal and state permits required for the Natrium nuclear plant and its associated fuel needs.

The Company's point that no natural gas plants bid into the 2020AS RFP is well-taken, and it may be that the developers' appetite for these projects is low. However, it is worth noting that although the 2020AS RFP did state that it would accept new natural gas resources, the RFP itself stated in the first paragraph:

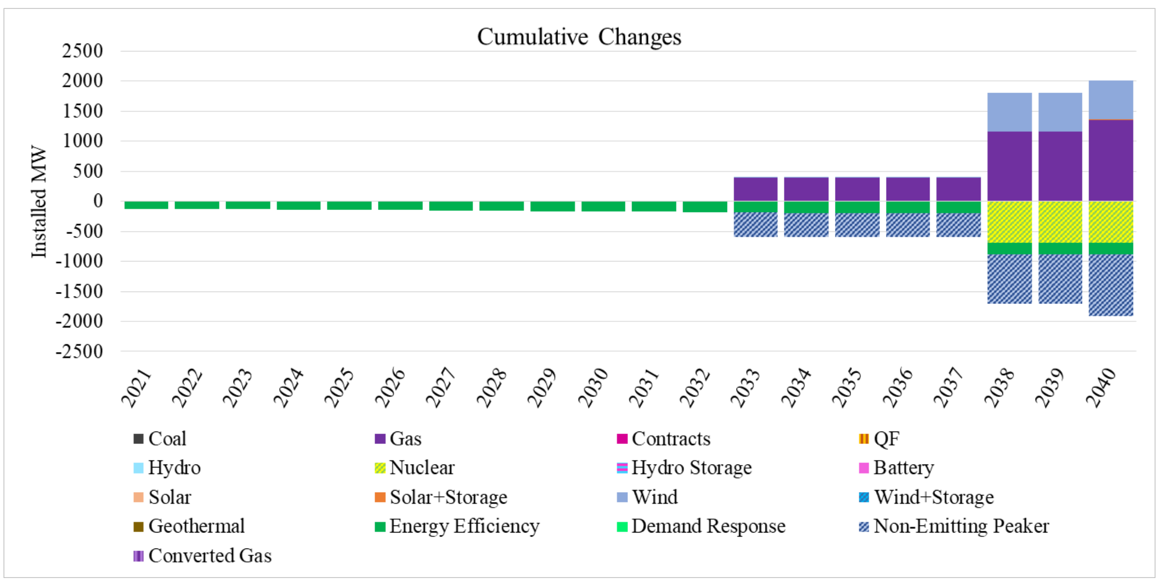
> The 2019 IRP preferred portfolio includes 1,823 megawatts (MW) of new proxy solar resources co-located with 595 MW of new proxy battery energy storage system (BESS) capacity and 1,920 MW of new proxy wind resources by the end of 2023.

If the Company's IRP selected a new natural gas peaker plant, and this fact was announced in the first paragraph of the RFP, it might have a more robust response from natural gas developers. The goal of the IRP is to determine the least-cost/least-risk portfolio, using all technically feasible resources, not to predict what developers might do. Furthermore, if technology or permitting for the preferred portfolio were to lag, necessitating a different set of resources to meet demand, the Company would be obligated to find the best way to meet that need under the new circumstances. The preferred portfolio contains resources that are not fully mature. Limiting its consideration of alternatives in modeling could leave the Company unprepared to meet needs and is imprudent.

The Company Performed a Sensitivity Analysis with New Gas Allowed

In response to a request from the Division, the Company performed sensitivity “New Proxy Gas—S04): “In this sensitivity, new gas peaking resources replace non-emitting peaking resources and new combined cycle combustion turbines replace advanced nuclear resources.”[83] The results from this sensitivity are shown in the figure below. The Division’s understanding is that when natural gas plants are allowed, the model selects natural gas peakers instead of non-emitting peaker plants in 2033, and combined cycle combustion turbines instead of new nuclear in 2038.

Figure 2 Sensitivity S04—Changes from P02-MM-CETA[84]

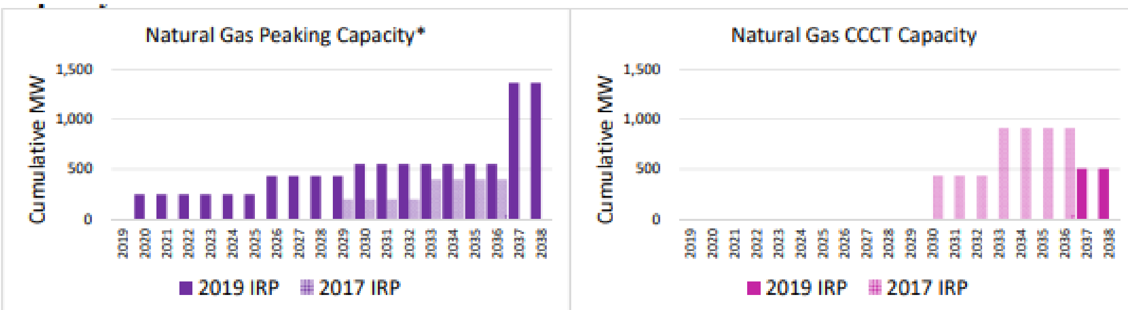


The results from Sensitivity S-04 are more consistent with the results from the 2019 IRP preferred portfolio, which had new natural gas peaking capacity added in 2026, 2030, and 2037 (see figure below). The 2019 preferred portfolio also had natural gas CCCT capacity added in 2037. The 2019 IRP results and the Sensitivity S-04 results indicate that if natural gas peakers

[83] 2021 IRP Vol. I, p. 252.
[84] CONFIDENTIAL RMP Attachment 13 – Sensitivity Documents – Compares 10-1-2021, file “21IRP 20yr_S04-MM+NewGas (25928) less 21IRP 20yr_P02-MM-CETA (18609) CONF.xlsx” tab “Charts for Document”. (Although the Excel sheet has confidential information, this chart is not confidential.)

and capacity are allowed in the base modeling, the model may select them as part of a least-cost, least-risk portfolio.

Figure 3 Figure 1.10 from 2019 IRP (2019 IRP Preferred Portfolio Natural Gas Peaking and Combined Cycle Capacity)



* Note: 2019 IRP natural gas peaking capacity includes the conversion of Naughton Unit 3 to natural gas in 2020 (247 MW).

For the reasons listed above, the Division recommends that natural gas be included in the main modeling runs as an available resource. If this is not feasible due to time constraints, the Division request that natural gas be modeled as an available resource in the next IRP, and if not, a robust quantitative analysis should be performed showing why natural gas is not part of a least-cost, least-risk planning process.

This request for inclusion of gas resources in IRP modeling is not a judgment by the Division that new gas resources are destined to be part of the least cost, least risk portfolio. That is unclear and depends on significant qualitative judgments, of the type the Company made, in addition to quantitative analysis. Nevertheless, such modeling would better reveal the options if the still-nascent options included in the Company's modeling do not become available as predicted.

7. Review of the Company's Load Forecast and Natural Gas Price Forecast

In Section 3 of these Comments above, the Division discussed how small changes in outputs could have large effects in "out" years, and so the Company should exercise caution in putting too much weight on expensive resource decisions that are many years out. In this section, we examine the load forecast and natural gas forecasts in turn to illustrate this issue.

RMP Load Forecast Overview

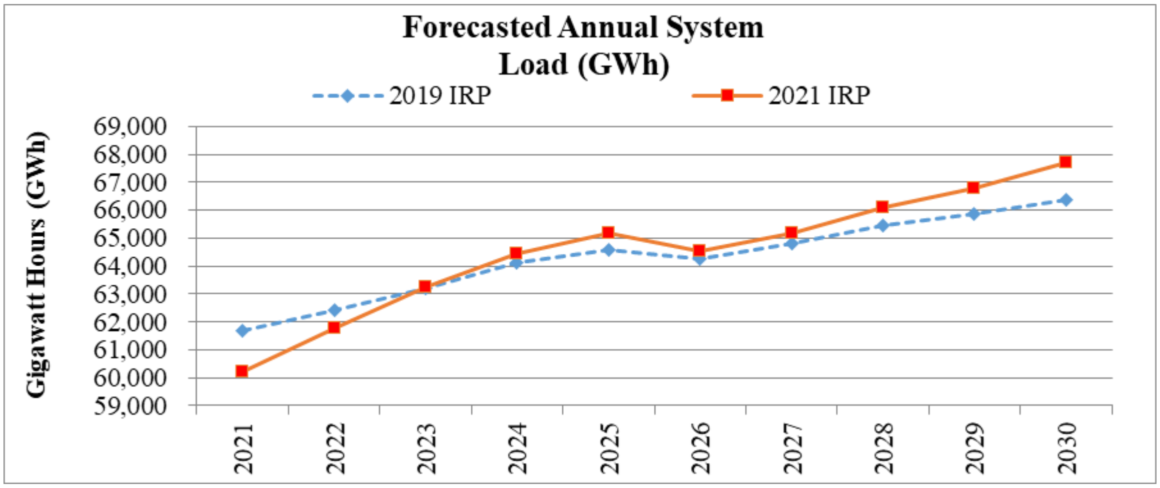
Generally, the Company's load forecast "is developed by forecasting the monthly sales by customer class for each jurisdiction"[85] and uses different forecasting methods for different classes. The main classes are residential, commercial, industrial, irrigation, and street lighting. The compound annual growth rate of forecasted load at generation for the 10-year period (2021 through 2030) is 1.31 percent. Factors that are driving trends across the system include the higher projected demands from data centers, which are driving up projected commercial forecasts, and residential forecasts.[86] After accounting for 13 percent planning reserve margin targets, coal unit retirements from the preferred portfolio, expected front-office transactions (FOTs) and other resources such as energy efficiency, the system is expected to be capacity-deficient in both the winter and summer peaks throughout the planning period (before new resources are considered).

Load Forecast

The Division reviewed the load forecast methodology for the 2021 IRP and its use in the load and resource balance. The load forecast was updated in June 2020[87] and the compound annual load growth rate for the 10-year period (2021 through 2030) is 1.31 percent.[88] Relative to the load forecast in the 2019 IRP, the load forecast requirement has decreased in all jurisdictions other than Utah and California in the 2021 IRP. The PacifiCorp system load requirement for 2030 has increased by 2.06 percent from the 2019 IRP to the 2021 IRP. Figure A.1 has a comparison of the load forecasts from the 2021 IRP to the 2019 IRP.

[85] 2021 IRP, Vol. II, Appendix A, p. 14.
[86] 2021 IRP, Vol. I, p. 12.
[87] 2021 IRP, Vol. II, Appendix A, p. 1.
[88] *Id.*

Figure 4 IRP Figure A.1 PacifiCorp System Energy Load Forecast—2019 IRP vs. 2021 IRP



In general, the Division finds that the load forecast was conducted with modeling and techniques appropriate to the industry.

Annual Energy Load Forecast

PacifiCorp utilizes software and services, including ITRON and SAE, to record, model and forecast. PacifiCorp performs a historical comparison to forecasted results in its analysis and forecast methodology. PacifiCorp developed alternative load growth scenarios for system demand and presented its long-term preferred forecast for each state and the system, summarized in IRP 2021 Volume II, Appendix A – Load Forecast Details.

PacifiCorp's 2021 IRP Table A.1 estimates the forecasted annual system load at generation over a 20-year period.[89] PacifiCorp employed "econometric models that use historical data and inputs such as regional and national economic growth, weather, seasonality, and other customer usage and behavior changes" in the development of this table.[90] PacifiCorp provided the Division with an Excel file entitled "Load Forecast History" that contained the information from Table A.1 as

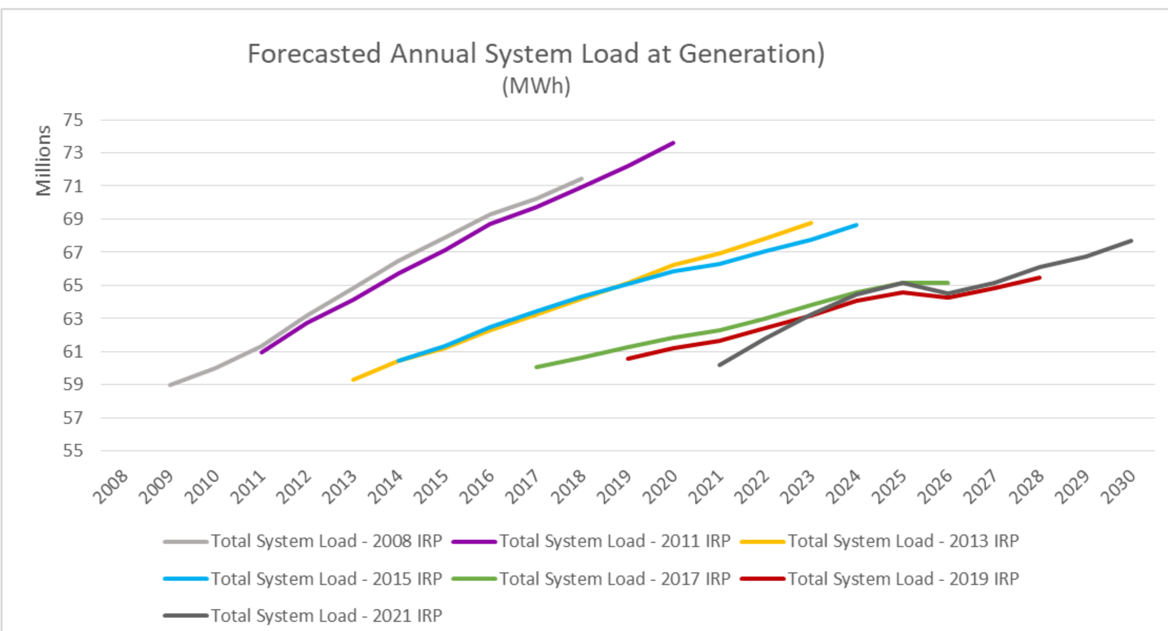
[89] Table A.1, Forecasted Annual Load, 2021 through 2030 (Megawatt-hours), at Generation, pre-DSM, 2021 IRP, Vol. II, Appendix A, p. 2.
[90] 2021 IRP, Vol. II, Appendix A, at 1.

well as the forecasted annual load data tables from each of PacifiCorp's prior IRP filings since 2008.

Growth in Actual Retail Sales vs. Growth in Projected Load

Table A.8 in the 2021 IRP records actual retail sales at the meter.[91] Table A.1 show forecasted annual load at generation. The Division compiled the Table A.1 data from the last several IRPs (for both the system as a whole, and for Utah) in the following figures (Division Figure 5 and Figure 6). The lines represent the forecasted annual loads (Table A.1) from the 2021 IRP and from past IRPs. From Figure 5 it is clear that with respect to the forecasted system load, the Company almost always errs on the side of higher load growth: the load at generation is typically predicted to rise steadily throughout the forecast, but for the most part, those increases do not occur. For Utah, the discrepancy is not as pronounced, but it is still present.

Figure 5 Forecasted Annual System Load at Generation (by IRP)

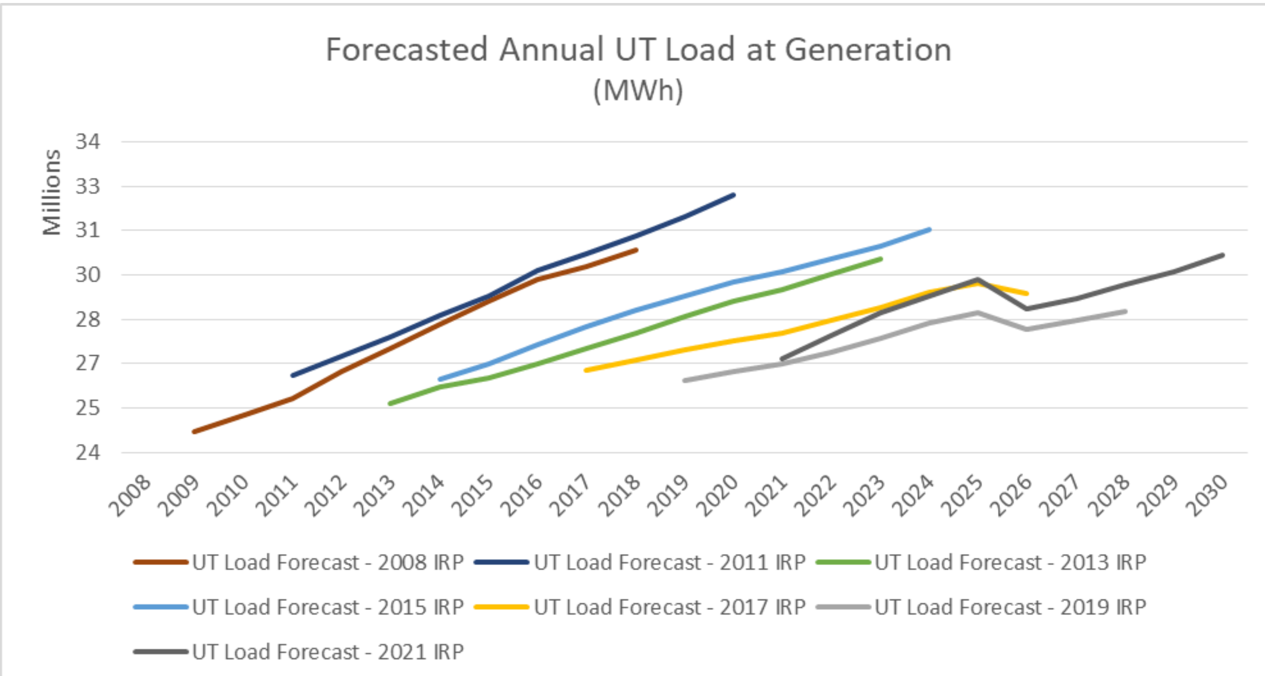


As observed in Figure 5, PacifiCorp's forecast load growth at generation is consistently higher than the actual growth rate from 2008 to 2019. Each IRP cycle begins close to the same starting

[91] *Id.* at 16.

point with a substantial growth rate. Figure 6 below is the same information presented with the growth projections for Utah. While it is expected that the Company will forecast growth in order to have sufficient capacity, the growth estimate results in additional resource requirements.

Figure 6 Forecasted Annual Utah Load at Generation (by IRP)

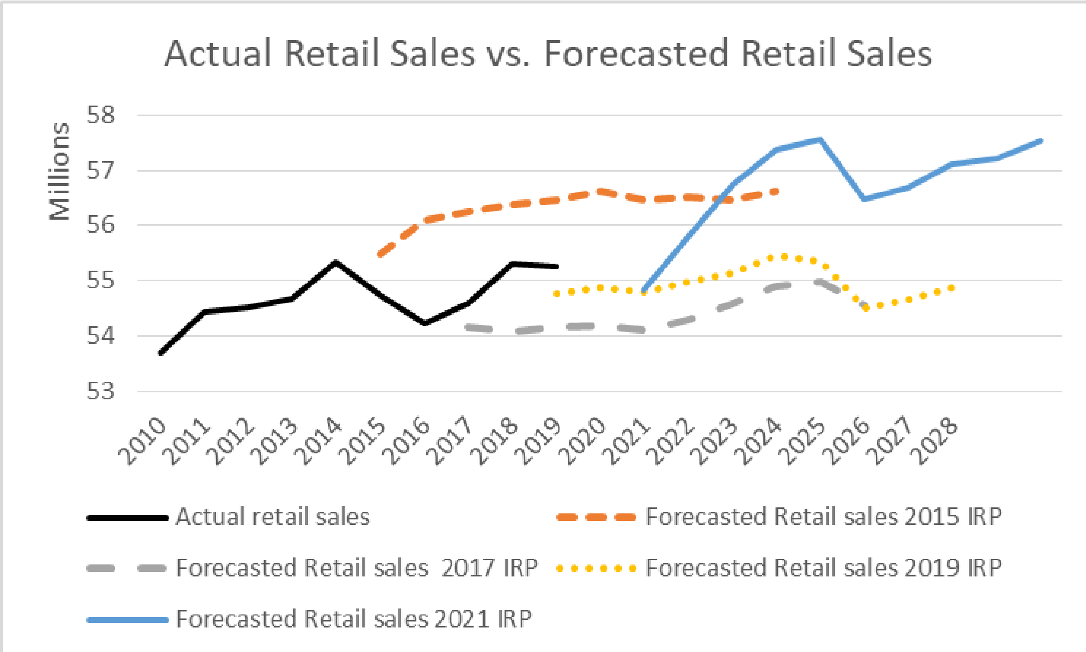


Forecasted Retail Sales vs. Actual Retail Sales

In its 2019 IRP Reply Comments, the Company suggested that a comparison of its forecasted retail sales and its actual retail sales could also be performed.[92] In the following figure, the Division makes this comparison for the last four IRPs:[93]

[92] *Rocky Mountain Power's Reply Comments*, Docket No. 19-035-02, PacifiCorp's 2019 Integrated Resource Plan, March 2, 2020, p. 23.
[93] Table A.8 in 2021 and 2019 IRPs; "System Retail Sales" in the 2017 and 2015 IRPs.

Figure 7 Actual System Retail Sales vs Forecasted Retail Sales



This figure shows that there is large variability from IRP to IRP. For example, the 2019 IRP projected retail sales of 55.35 million MWh in 2025, while the 2021 IRP projected 57.56 million MWh in that same year—a difference of 2.2 million MWh. This shows again how different inputs (in this case, inputs into the load forecast, such as employment and other economic inputs) can have large effects, even in the short term. Small changes in the inputs can have large impacts on resource planning and future resource allocations. Thus, caution should be used when evaluating large, costly resources, especially in the out years, based on the latest load forecast.[94] The IRP forecast projects a significant increase in retail sales from 2021 through 2025 and then a significant reduction in 2026. This sharp rise and then fall-off is not consistent with historical

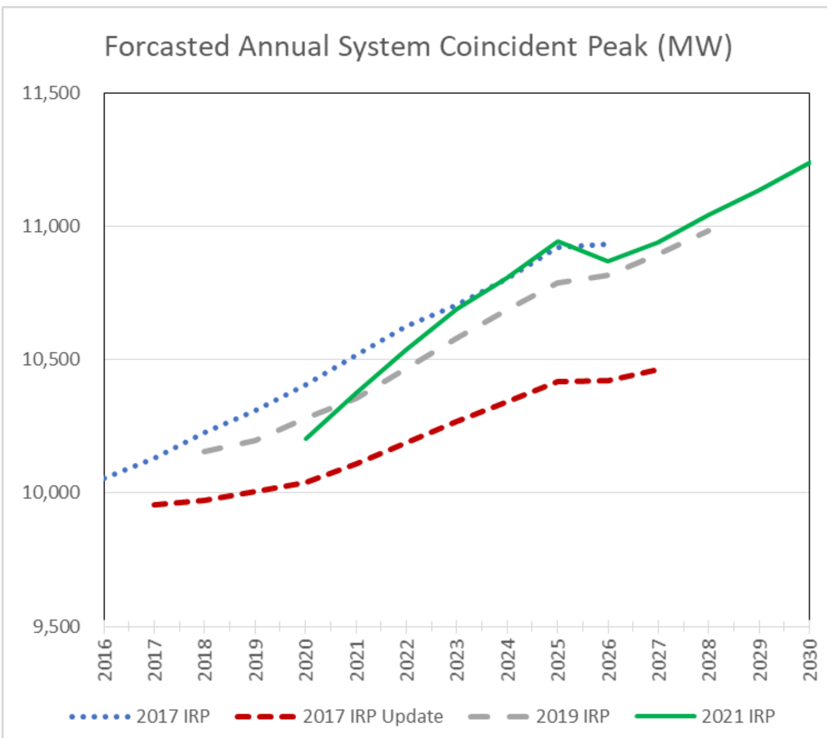
[94] Docket No. 11-035-73 provides a good illustration of this point. In early- to mid-2011, the Company began the process of getting Commission approval to solicit a 600 MW resource to be available in 2016. That resource procurement process continued until the Company's notice in late 2012 that it would no longer be pursuing a new resource because its load forecast and resource assumptions and projections had changed. Modest changes to load and other incremental changes to assumptions about existing resources resulted in cancellation of what would have been a generations-long capital investment. (See September 28, 2012 Resource Needs Assessment Update for the All-Source Request for Proposals for a 2016 Resource.) If a load forecast change and relatively modest resource assumption changes could swing such a large resource decision within just a few years of its proposed in-service date, decision makers should be very wary of what can be well-understood about the later years of an IRP's forecasts.

growth rates or previous forecasts and has not been sufficiently explained. The forecasted growth rates have often not panned out.

Forecasted Peak from IRP to IRP

For another example, Figure 1.8 in the 2021 IRP compares the forecasted annual system peak for years 2021 to 2039, as forecasted by the 2019 IRP and the 2021 IRP. As the right side of the figure shows, those two forecasts are fairly close.[95] However, a similar comparison for the last few IRPs shows a bigger difference, as shown in the following figure.[96]

Figure 8 Load Forecast Comparison between Recent IRPs (Before Incremental EE Savings)



The peak load for 2025 is around 10,400 MW in the 2017 IRP Update, but it is over 10,900 MW in the 2021 IRP update—a difference of 500 MW. This is the size of a gas or coal baseload unit,

[95] Figure 1.8, 2021 IRP Vol. I, p. 13.
[96] Forecasted annual system coincident peak, taken from last four IRPs (scale magnified to show detail). The current IRP data is in Table A.2, 2021 IRP Vol. II, p. 3.

or multiple wind projects—and is close to the maximum capacity of the Natrium plant, with storage at full. The point is not to denigrate the Company's forecasts; its forecasting team does an excellent job creating forecasts in a changing environment. The point is that small changes in inputs from year to year in that same changing environment can have huge impacts in the planned resources in the out years.

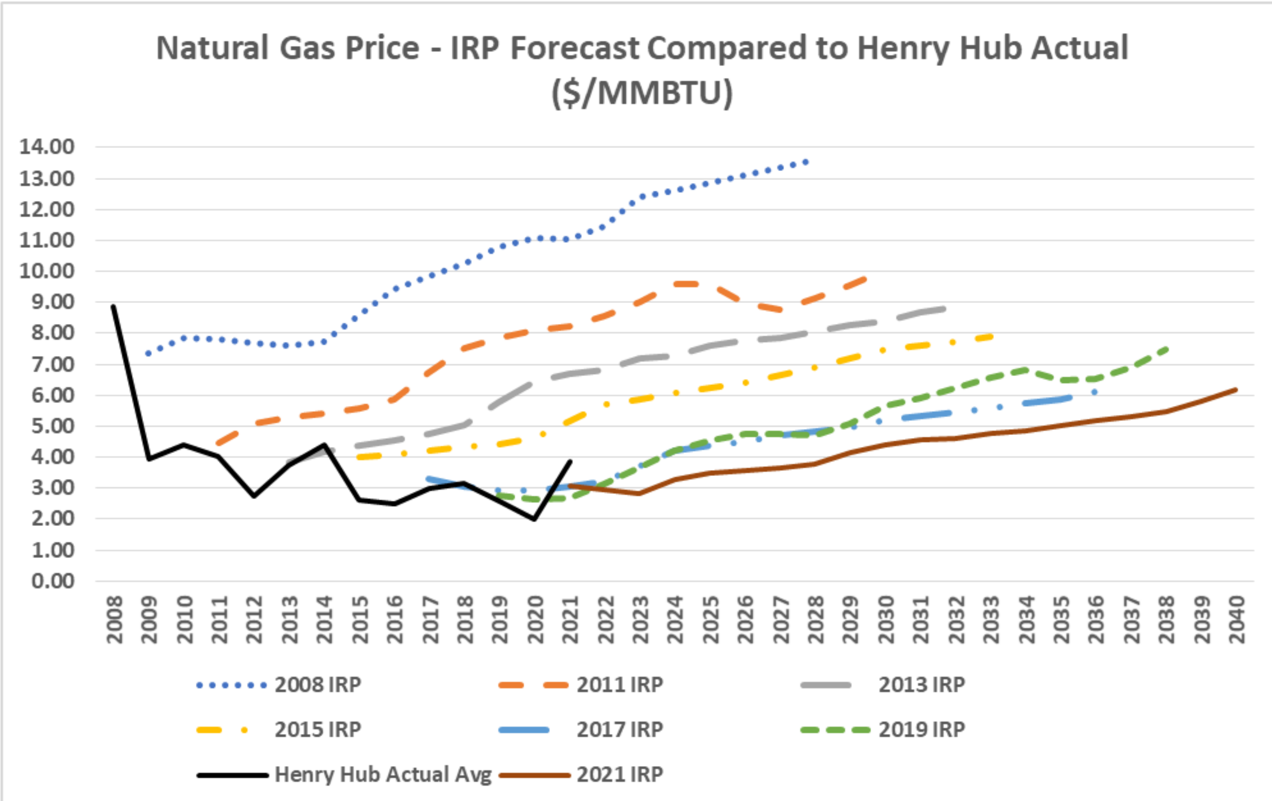
Natural Gas Forecast

PacifiCorp is exposed to natural gas price risk due to its natural gas-fired generating fleet and the interrelationship of natural gas to other fuel sources. A price change in natural gas may sway the price of electricity. For IRP modeling purposes PacifiCorp used the official forward market and projections from third-party experts. The gas price forecast in 2021 IRP is lower than the gas price forecasts in the 2019 IRP due to "assumption of lower natural gas prices than the 2019 IRP."[97]

PacifiCorp's Figure 1.10 records the base case forecast of natural prices based on prices in the forward market and projections from third-party experts.[98] PacifiCorp provided the natural gas price projections found in Figure 1.10 and in prior IRPs since 2008, with the actual Henry Hub spot price history as a response to DPU data request set 6.1. The following graph shows the Division's findings:

[97] 2021 IRP, Vol. I, p.14.
[98] *Id*. at 13 and 14 (Comparison of Power Prices and Natural Gas Prices in Recent IRPs).

Figure 9 Natural Gas Price - IRP Forecast Compared to Henry Hub Actual



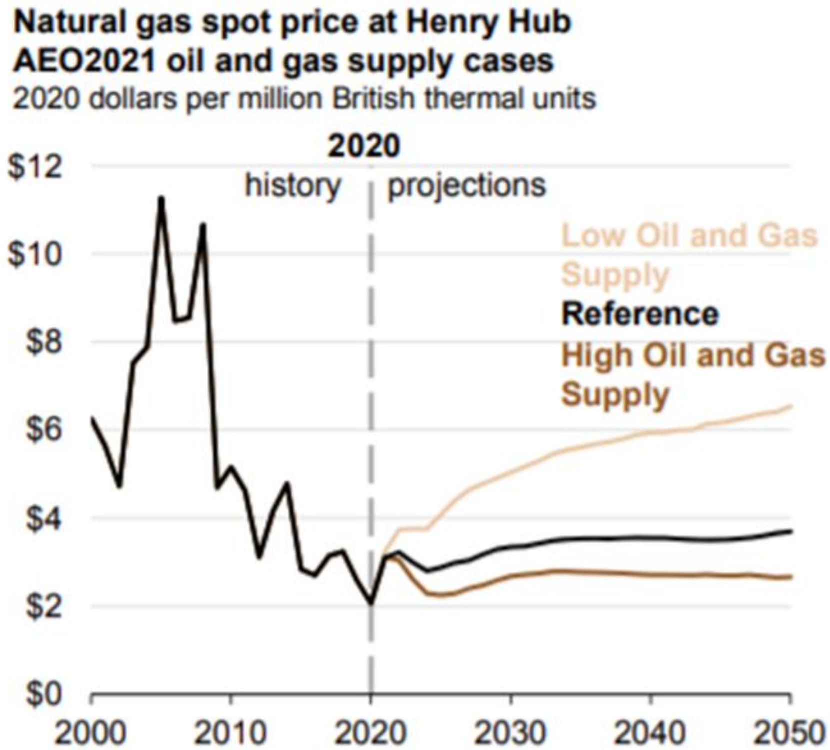
The Division's comparison graph demonstrates that the future price of natural gas has mostly been overestimated in IRPs since 2008. Henry Hub is used here as a rough proxy of natural gas price trends.[99]

The Division also compared PacifiCorp's 2021 IRP natural gas forecast with the natural gas price at the Henry Hub forecasted in the February 03, 2021 Annual Energy Outlook 2020 with projections to 2050 (AEO2020). The AEO2020 was prepared by the U.S. Energy Information Administration (EIA).

The AEO2020 modeled 5 case projections for natural gas prices at Henry Hub through 2050. Each projected scenario includes different assumptions about economic growth, energy supply,

[99] *Id*. at 37

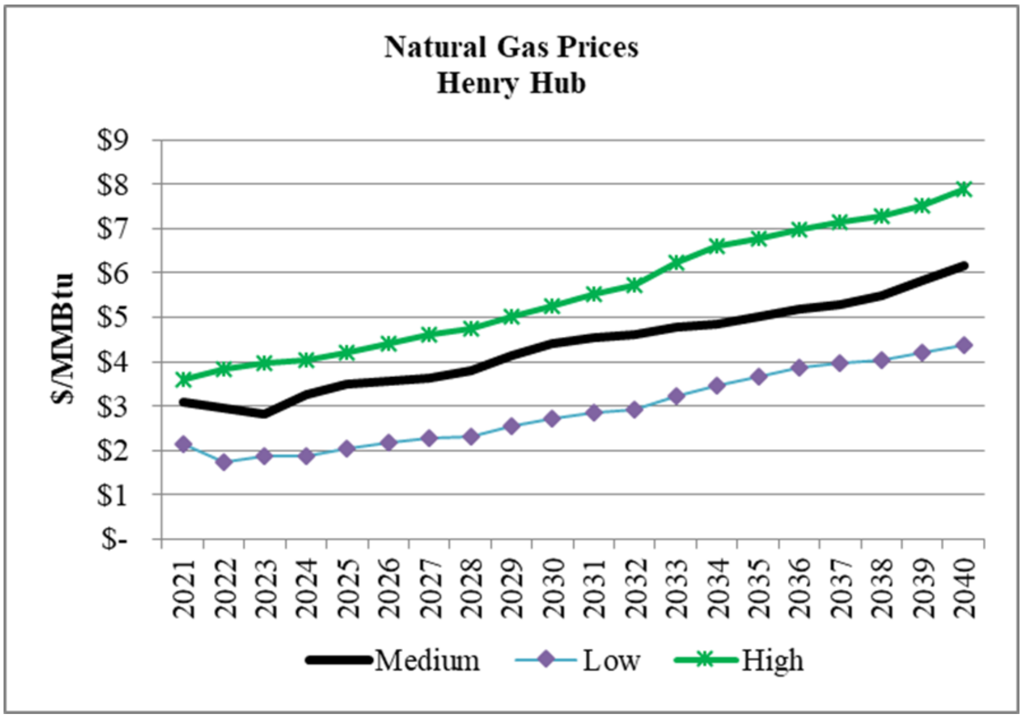
and technological progress. The EIA forecast each of these five scenarios in the following chart:[100]



[100] Annual Energy Outlook 2021 with projections to 2050 (AEO2020), February 03, 2021, p.23.

The Company's medium, high, and low Henry Hub prices are shown in their Figure 8.5, which the Division has extracted in the chart below.

Figure 10 Figure 8.5 from 2021 IRP (Nominal Wholesale Electricity and Natural Gas Price Scenarios)



Under the EIA's Reference scenario, projected natural gas prices would be lower than $4 per million British thermal units (MMBtu) through 2050. In comparison, PacifiCorp forecasts the price of natural gas at almost $6.16 per MMBtu by 2040.[101]

For the year 2040, PacifiCorp's "Medium" forecast for natural gas is close to EIA's worst-case scenario (shown on EIA's graph as "Low Oil and Gas Supply")—both are right around $6 per MMBtu. The Company's "low" gas forecast reaches $4.38 MMBtu in 2040; this is significantly higher than the EIA's reference case, which remains well below $4 per MMBtu in 2040.

[101] See Figure 8.5 in the 2021 IRP, Vol. I, p. 228 (and accompanying data disk).

This comparison of EIA's and PacifiCorp's forecasts was provided as an outside reference and view on the trending future price of natural gas, not to imply an indication of preference in any particular model or forecasting methodology. From past conversations with the Company, the Division acknowledges that EIA forecasts are not usable for the Company's modeling, for a number of reasons. The comparison with the EIA forecast is simply a reminder of the large impact that different natural gas price forecasts can have on the preferred portfolio and other aspects of the IRP.

Again, the Division is not criticizing the Company's natural gas price forecast. It is simply pointing out that there are a wide range of "reasonable" gas price forecasts, and the resources selected in the later years of a given IRP can vary significantly depending on which reasonable forecast was used. For example, if the Company used the EIA reference case (and allowed natural gas in its preferred portfolio modeling), its 2021 preferred portfolio might look quite different.

Relying on load forecasts and gas forecasts that are just one of many reasonable options, and which may be consistently overestimated and underestimated, respectively, could lead to ineffective decisions in resource selection and allocation. For that reason, decision makers should seek to fully understand the forecasts being used and any assumptions or biases in them. For example, if a specific forecast uses a high number of actual market measures in early years, but then escalates those numbers in out years to account for risks or other factors, care should be taken. Using that forecast to derive a PVRR as a measure of potential cost or savings of one resource over another may be unwise, particularly if the cost or savings is not very large. This should be kept in mind for long-term, high-cost projects such as large transmission upgrades, nuclear plants, and proxy peaker plants of unknown technology. When a decision is being made about whether to shutter an existing facility early to take advantage of potential savings, the decision makers should be especially humble about what the forecasted cost or savings can actually reveal.

Carbon Cost Forecasts

The Plexos long-term (LT) model, medium-term (MT) model and short-term (ST) model are new to PacifiCorp in the 2021 IRP cycle. Roughly speaking, the LT model is used to produce 20-year portfolios that vary by the type, timing, location and magnitude of new resources, and by retirement dates of current resources. The MT model performs stochastic risk analysis on each portfolio, based on three natural gas price scenarios (low, medium, and high) and four carbon dioxide (CO_2) price scenarios. The four CO_2 price scenarios in the 2021 IRP are zero, medium, high, and a price forecast that aligns with the social cost of greenhouse gases (SCGHG). The SCGHG scenario was added to comply with RCW 19.280.030.[102]

Altogether, there are five distinct price-policy scenarios that are used in the MT modeling step to evaluate for cost and risk for each portfolio:[103]

1. Medium gas/medium CO_2
2. Medium gas/zero CO_2
3. High gas/high CO_2
4. Low gas/zero CO_2
5. Medium gas/social cost of greenhouse gas (SCGHG) scenario

The IRP uses five electricity price forecasts, as described below:

> PacifiCorp's OFPC for electricity and each of its five scenarios were developed from one of three (medium, low, high) underlying expert third-party natural gas price forecasts in conjunction with one of four CO2 price scenarios. … The OFPC used in the 2021 IRP does not assume any CO2 policy or tax in conjunction with its medium gas price forecast. *However, PacifiCorp's 2021 IRP "medium case" price forecast is not the OFPC but a scenario that couples medium gas with a medium CO2 price*, applied for forecasting purposes as a tax. Thus, *the 2021 IRP medium case* differs from that of the March 2021 OFPC by *assuming a medium*

[102] *Id*. at 226. See Section 8 for more on this.
[103] 2021 IRP Vol. I, p. 217.

> *CO2 price starting in 2025*. This medium CO2 price serves as a proxy for a potential future CO2 policy.[104]

Thus, the Division's understanding is that the medium (MM) case used in the preferred portfolio already has a cost of carbon in it starting in 2025, as does the S-04 sensitivity discussed above. Therefore, the S-04 sensitivity selected new gas resources even with a cost of carbon in place.

The Division notes that political considerations make a federal carbon price in the next ten years somewhat unlikely. Whether the U.S. Congress could foreseeably pass a carbon tax, or similar policy, in the next decade is an open question. Although states might impose their own costs, Utah's IRP should not be determined by those states' policy choices. A state level cost of carbon is unlikely to be imposed by Utah in the next decade. Although there are likely to be considerations relative to carbon costs that affect policy, like federal regulatory mandates to consider such costs, there is no currently imposed or reasonably foreseeable carbon tax or direct price that warrants considering carbon costs in every scenario modeled. The Division recommends that the Commission require the Company in future IRPs and IRP updates to run modeling cases similar to "S-04-MM+New Gas (25928)": with gas allowed to be selected, with no cost of carbon (added as an external cost, or built in to electricity process), and no nuclear, and that a figure of the type shown above in Figure 2 be produced.

8. Effect of State Policies on PacifiCorp's IRP

It is increasingly important to recognize the effect of federal and state public policies in shaping the Company's IRPs. The 2021 IRP was influenced by such policies, and the Company's future IRPs may be affected to an even greater extent. The Company acknowledges the "major" external influence that public policy and regulatory initiatives have on its long-term resource planning and recent procurement activities.[105] The Company cites other external influences, such as trends in the economy, wholesale power, and natural gas prices that also affect the environment in which the Company operates.[106] Over the past few years there have been many

[104] *Id.* at 228 (emphasis added, footnotes omitted).
[105] 2021 IRP, Volume I, p. 38.
[106] *Id.*

significant state policy changes centered on climate change and pollutants such as carbon dioxide emissions. The Division intends to discuss only a handful of these changes that have the most direct effect on Utah and the IRP.

The Division's IRP comments in this section discuss the effects of other state policies on the resulting IRP. These effects specifically concern "cost" and "risk" and how other state mandates affect what Utah ratepayers could be paying for or benefiting from in the long-term. Of course, these remain hypothetical at this point. But the structural change exists.

This Commission should ensure that the Company's IRP serves the long-run public interest as determined in accordance with Utah law. Utah ratepayers should not be put at an unacceptable level of risk or left burdened with a disproportionate share of costs for resource selections that are planned primarily to meet other state energy policies.

At the heart of Utah's IRP Standards and Guidelines, the Commission states the following:

> The Commission will require PacifiCorp to pursue the least cost alternative for the provision of energy services to its present and future ratepayers that is consistent with safe and reliable service, the fiscal requirements of a financially healthy utility, and the long-run public interest.[107]
>
> …
>
> The Commission finds that the jurisdictional needs of Utah will be a primary consideration in the Commission's evaluation of the Company's IRP. However, where possible and when minimal impact on Utah's interests exists, coordination with other jurisdictions will be pursued.[108]

The utility planning process must evaluate "all known resources on a consistent and comparable basis, in order to meet current and future customer electric energy services at the lowest total cost to the utility and its customers…"[109] The Commission determined that lowest cost should be defined as "Total Resource Cost" and recommended that sensitivity analyses be performed for

[107] *Standards and Guidelines*, Docket No. 90-2035-01, p. 1.
[108] *Id.* at 16
[109] *Id*. at 17-18.

external costs, rather than explicitly including such costs in the definition.[110] Finally, the Utah Commission requires that conclusions be based on analysis, not assumptions.[111]

Washington State Mandates

CETA. The Washington Clean Energy Transformation Act (CETA), enacted in 2019 as Senate Bill 5116, requires all electricity sold in that state to be greenhouse gas neutral by 2030, meaning utilities can still generate power from sources like natural gas, as long as those emissions are offset elsewhere. But under this act, by 2045 offsets are no longer sufficient and all retail electricity must come from renewable or non-CO2-emitting sources.[112] PacifiCorp's IRP describes some of the required energy targets:[113]

- By 2025 utilities remove coal-fired generation from Washington's allocation of electricity.
- By 2030, Washington retail sales will be carbon neutral.
- By 2045, Washington retail sales will be 100% renewable and non-carbon-emitting.

Along with these clean energy targets, utilities in Washington must ensure that their customers and communities are benefitting equitably from the transition to renewable energy, with the formation of the Equity Advisory Group (EAG) to monitor success. Washington's investor-owned utilities, such as PacifiCorp, must develop and implement plans to reduce carbon emissions or pay penalties for failing to meet requirements of the law. Penalties for non-compliance can be $100/MWh with a multiplier if the utility is otherwise unable to comply.[114]

CEAP. The Clean Energy Action Plan (CEAP) is a first-time addition to the Company's 2021 IRP as required by the state of Washington. Appendix O in Volume II of the IRP contains details of the CEAP. Briefly, the CEAP provides a Washington-specific look at what resources may be added or retired from the state's allocation of electricity over the next 10 years. The

[110] *Id*. at 18-19.
[111] *Id*. at 23.
[112] Clean Energy Transformation Act (wa.gov)
[113] 2021 IRP, Volume I, p. 289.
[114] See https://www.pacificorp.com/energy/washington-clean-energy-transformation-act-equity.html

CEAP provides a way to look at the mix of resources the Company plans to serve its Washington customers and communities in the next ten years progressing toward a clean and equitable energy future that complies with CETA.[115]

Social Cost of Greenhouse Gas Emissions. PacifiCorp's 2021 IRP includes the social cost of greenhouse gas emissions (SC-GHGs) as a cost adder,[116] as required in the CEAP and as documented in the Revised Code of Washington (RCW) 19.280.030, titled "Development of a resource plan—Requirements of a resource plan—Clean energy action plan." This section states the following: [117]

> (3)(a) An electric utility must incorporate the social cost of greenhouse gas emissions as a cost adder when:
> (i) Evaluating and selecting conservation policies, programs, and targets;
> (ii) Developing integrated resource plans and clean energy action plans; and
> (iii) Evaluating and selecting intermediate term and long-term resource options.

The Company incorporated the SC-GHGs in all the above ways, as well as in modeling its imports, contracts, forward price curves, and in portfolios that were considered to ultimately inform the 2021 IRP.[118] The SC-GHGs are assumed to start in 2021[119] and are applied such that the price for the SC-GHGs is reflected in market prices and dispatch costs. In other words, the SC-GHGs are incorporated into capacity expansion optimization modeling. System operations also include the SC-GHGs once the portfolios are determined.

The IRP identifies a risk as follows:

> this operational assumption will not be aligned with actual market forces (i.e., market transactions at the Mid-Columbia market do not reflect the social cost of

[115] *Id.*
[116] https://costofcarbon.org/faq/what-is-the-scc
[117] https://app.leg.wa.gov/RCW/default.aspx?cite=19.280.030.
[118] 2021 IRP, Volume II, p. 45; Volume I, p. 226.
[119] *Id.*

> greenhouse gases and PacifiCorp does not directly incur emission costs at the price assumed for the social cost of greenhouse gases).[120]

Therefore, unlike the other price-policy scenarios, the model results for the social cost of carbon price-policy scenario represent cost drivers that are materially divergent from the cost drivers in the market. This creates challenges in understanding how to interpret the results from this price-policy scenario.

The Company's social cost of greenhouse gas price-policy scenario assumes emissions pricing as specified in Table 2 of the Interagency Working Group on social cost of greenhouse gas produced by the United States Government.[121] The Division notes a significant change from the Company's 2019 IRP's social cost of carbon (SCC) case. This is the required shift from the 3.0 percent "average" discount rate to the 2.5 percent "low" discount rate. This change increases the SC-GHG base pricing by an average of 49 percent in the 5-year intervals specified by the table.

To comprehend the impact of this, the Company found that on average, portfolios run under the SCGHG price-policy scenario incur $12.1 billion of additional costs above portfolios run under the MM price-policy assumption.[122]

CEIP. The Clean Energy Implementation Plan (CEIP) is also new to the Company's 2021 IRP and includes a near-term, four-year action plan specific to Washington customers and communities that focuses on community-based actions to move toward meeting CETA's milestones. The Company filed a CEIP public participation plan with the Washington Utilities and Transportation Commission (UTC) and an update to the plan on July 30, 2021.[123] The Company filed its first draft CEIP for the years 2022 through 2025 on November 1, 2021[124] and

[120] *Id.*, Volume I, p. 226.
[121] https://costofcarbon.org/faq/what-is-the-scc.
[122] See PacifiCorp's August 27, 2021, Public Input Meeting Materials, p. 44.
[123] *PacifiCorp's Draft Clean Energy Implementation Plan (Draft CEIP)*, UE-210829, November 1, 2021.
[124] *Id.*

a final CEIP on December 30, 2021. [125] PacifiCorp must file a new CEIP with the UTC every four years.[126]

The UTC also oversees the Company's compliance with the Energy Independence Act (EIA) that establishes renewable portfolio standard (RPS) targets that increase over time.[127] The CETA legislation has transformed electric utility resource plans and re-written the requirements of resource planning in Washington.[128] This state specific plan is then carried through to the Company's resource plan that is by its very definition an integration of all its states' service plans. Part of the transformation requires utilities to conduct three scenarios that the Company described in its 2021 IRP:[129]

- Climate Change - WAC 480-100-620(10)(b) instructs utilities to "incorporate the best science available to analyze impacts including, but not limited to, changes in snowpack, streamflow, rainfall, heating and cooling degree days, and load changes resulting from climate change." [130] The 2021 IRP states elsewhere: "Compared to the preferred portfolio, the climate change scenario increases system costs by $14.6 billion, driven in large part by the SCGHG price-policy assumption."[131]
- Maximum Customer Benefit - WAC 480-100-620(10)(c)[132] instructs utilities to "model the maximum amount of customer benefits described in RCW 19.405.040(8)[133] prior to balancing against other goals." The 2021 IRP states elsewhere: "The Maximum Customer Benefits sensitivity increases costs by $16.9 billion relative to the preferred portfolio, driven primarily by the SCGHG price-policy assumption and the inclusion of all available DSM."[134]

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[125] https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/ceip/PAC-CEIP-12-30-21_with_Appx.pdf.
[126] *Id.*
[127] See https://www.commerce.wa.gov/growing-the-economy/energy/energy-independence-act/.
[128] For example, see https://app.leg.wa.gov/RCW/default.aspx?cite=19.405, https://app.leg.wa.gov/RCW/default.aspx?cite=19.280.030, https://app.leg.wa.gov/RCW/default.aspx?cite=19.405.040.
[129] 2021 IRP, Volume I, p. 249.
[130] *Id.*
[131] 2021 IRP, Volume I, p. 314.
[132] *Content of an integrated resource plan*, WAC 480-100-620, at: https://app.leg.wa.gov/WAC/default.aspx?cite=480-100-620
[133] *Greenhouse gas neutrality—Responsibilities for electric utilities—Energy transformation project criteria—Penalties*, RCW 19.405.040, at https://app.leg.wa.gov/RCW/default.aspx?cite=19.405.040.
[134] 2021 IRP, Volume I, p. 315.

- Alternative Lowest Reasonable Cost - WAC 480-100-620(10)(a)[135] instructs utilities to "describe the alternative lowest reasonable cost and reasonably available portfolio that the utility would have implemented if not for the requirement to comply" with CETA's Clean Energy Transformation Standards.

The purpose of the alternative lower reasonable cost counterfactual is to yield a baseline portfolio that includes the SC-GHGs and differs from the CETA-compliant preferred portfolio according to rule.[136] In the absence of a requirement to assume SC-GHG during portfolio development, the alternative lowest reasonable cost portfolio is P02-MM, which would have been implemented but for CETA requirements. The preferred portfolio, P02-MM-CETA, adds a present value revenue requirement of $164 million compared to P02-MM to meet CETA requirements.[137]

Accounting for the requirement to include the SC-GHG price-policy assumption in portfolio development, the alternate scenario becomes the same as case P02-SC-GHG-MM. The Company ran the SC-GHG portfolio under the medium gas, medium CO_2 price-policy scenario.

Comparing the Alternative Lowest Reasonable Cost case (P02-SC-GHG-MM) to the preferred portfolio (P-02-MM-CETA) yields a PVRR(d) system cost that is anticipated to be *significantly higher*.[138] The Company did not provide further details on how high the costs would be.

The implementation of Washington mandates comes with a significant risk to Utah ratepayers. In the Company's evaluation of the P02-MM portfolio against the CETA targets, it made certain modeling assumptions to account for uncertainties related to the future of interjurisdictional cost allocation among the PacifiCorp states and resolution of outstanding CETA implementation issues.[139] The Company currently allocates costs and benefits, including resource costs and benefits, to Washington according to the Washington Inter-Jurisdictional Allocation

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[135] *Content of an integrated resource plan*, WAC 480-100-620, at: https://app.leg.wa.gov/WAC/default.aspx?cite=480-100-620
[136] 2021 IRP, Volume II, p. 43.
[137] See PacifiCorp's August 27, 2021, Public Input Meeting Materials, p. 51.
[138] *Id.*
[139] 2021 IRP, Volume I, at p. 290.

Methodology (WIJAM). The WIJAM expires December 31, 2023, and negotiations are underway among all six states to determine the next inter-jurisdictional allocation method.

Upon evaluation relative to the 2030 CETA target, the Company identified a shortfall of annual capacity that it met with Washington-situs assigned resources. The current 2020 Multi-State Protocol (MSP) can be characterized as presaging a fundamental shift in how the Company proposes to address inter-jurisdictional cost allocation, with the goal of moving away from the concept of a common generation resource portfolio with dynamic allocation factors and toward a cost-allocation protocol with fixed allocation factors for generation resources and state specific resource portfolios.

Under the 2020 Protocol, Utah ratepayers and the Company are in a gradual transition period relying upon the continuation of historic protocols through December 31, 2023, or upon the resolution of all remaining cost-allocation issues. New generation resources that begin operations after the interim period will be subject to future determination as part of the framework issues that have not been entirely resolved. It is possible no agreement will be reached and allocation issues will be decided separately by each state. Some of the Division's concerns with the MSP Process and the effect of Washington legislation are described below.

The Division is concerned about resource allocation risk attributable to the unsettled portions of the MSP cost allocation process after 2023. This means the costs and risks for projects such as the Natrium plant and non-emitting resources that have possibly been hard-wired into the 2021 IRP to meet Washington mandates, could inevitably leave Utah ratepayers at risk for a disproportionate share of costs for projects that potentially might not have been selected had it not been for Washington or Oregon state energy policies. This risk increases significantly as PacifiCorp develops its 2023 IRP, where Washington and Oregon state policies will be more fully implemented and the transition period in the 2020 Protocol ends. The Company acknowledges, and the Division recognizes, the complexities that state policies such as CETA create in planning for a multi-state utility such as PacifiCorp:[140]

[140] *Id*. at 47.

> [D]iverging state policies … and the incorporation of societal externalities in resource planning challenge the long-standing practice of planning for a single, integrated system.

The Division has not described the entirety of Washington's mandates above but suffice it to say that its CETA legislation has revised IRP planning guidelines and requirements, and each of these requirements come with costs and risks. As the legislation's title explains, this is a *major energy transformation* that affects all of PacifiCorp and all its ratepayers in one way or another: "Most notably, this can be seen through the Company's scenarios and sensitivities run as part of the portfolio modeling process, inputs to modeling assumptions such as the supply-side resource table and price-policy scenarios, and its portfolio modeling methodology and approach."[141]

Oregon State Policies

In July 2021, Oregon passed House Bill 2021 (HB 2021), which requires retail electricity providers to reduce greenhouse gas emissions by 80 percent below baseline emissions levels by 2030, by 90 percent below baseline emissions level by 2035, and by 100 percent below baseline emissions levels by 2040.[142] This 100 percent carbon-free electricity policy by 2040 surpasses Washington and even California, which were aiming at decarbonization of their electric grids by 2045.[143] HB 2021 encourages utilities to meet the targets in a manner that provides direct benefits to communities such as resiliency, health, and economic benefits. The emission targets are in addition to the state's current RPS guidelines. All Oregon utilities are required to craft plans that will reach the clean energy targets in alignment with their integrated resource planning process.

On March 10, 2020, Governor Kate Brown issued Executive Order No. 20-04 (EO), directing state agencies to take actions to reduce and regulate greenhouse gas emissions (GHG). Among other directives, the EO directed the Oregon Public Utility Commission (OPUC) to determine whether utility portfolios and customer programs reduce risks and costs by making rapid

[141] Pacific Power's 2022 Clean Energy Plan, Attachment A, Clean Energy Implementation Plan, p. 18.
[142] https://www.oregon.gov/puc/Pages/Legislative-Activities.aspx. See summary at: https://www.oregon.gov/puc/Documents/HB2021-Summary.pdf
[143] https://www.utilitydive.com/news/oregon-leaps-ahead-of-california-and-washington-as-legislators-ok-bill-to-d/602610/.

progress towards reducing GHG emissions.

In response, the OPUC has already proposed updating the IRP guidelines to more explicitly consider the costs and risks of meeting the state's GHG emission reduction targets under the new timelines set forth in EO 20-04. The Company has stated that the 2023 IRP will include a Clean Energy Plan and will show a pathway to clean energy standards. Its IRPs must consider HB 2021 beginning January 1, 2022.[144] The HB 2021 targets are aggressive and will likely require significant investment over a relatively short period of time, raising important cost and risk considerations and previously identified concerns regarding how resource costs will be allocated after the December 30, 2023, transition date in the 2020 Protocol ends.

The Company is required to provide a summary of what additional analysis it plans to provide to the OPUC regarding HB 2021 compliance prior to an acknowledgement decision on this IRP. The OPUC staff is already considering how PacifiCorp could perhaps reconfigure the Plexos modeling software to hand build a portfolio designed to achieve the HB 2021 emission targets, including going out to 2040.[145] In addition, the Division notes that OPUC staff has requested an understanding of how IRP models could also be utilized to explore GHG emission risks under stochastic scenarios by applying the societal cost of CO_2 beyond market prices policy scenarios and dispatch costs.[146] Much like Washington, Oregon utilities will have to file a clean energy plan as part of HB 2021. The OPUC and utilities are still implementing facets of HB 2021 and the impacts will be most notable during the acknowledgment phase of PacifiCorp's 2021 IRP and more so in the 2023 IRP.

Summary of State Policies

The Company mentions in the IRP the current framework issues in the MSP protocol:

> [A]s state energy policy continues to evolve, requiring the exclusion of certain generating resources, it appears infeasible to continue serving customers with a common generation portfolio and dynamically allocated system costs. As such,

[144] See PacifiCorp's July 30, 2021, Public Input Meeting Materials, p. 69.
[145] *OPUC Staff Report*, LC 77, December 23, 2021, p. 39.
[146] *Id.*

> PacifiCorp will work to meet its legal requirements as a public utility in each state in a risk-adjusted, least-cost manner, while striving to mitigate cost impacts in other states.[147]

In other places in the IRP, the Company repeats a similar sentiment: "The Company notes the challenges in complying with multi-state integrated planning, given differing state energy policies and resource preferences."[148] Uncertainty in the MSP allocations going forward will further complicate the 2023 IRP.

The Division is concerned with the IRP's transformation, particularly given the process shortfalls noted earlier. The IRP has transformed from being (in the simplest of terms), a primarily analytical modeling tool, where load forecasts, gas and electric prices, and other inputs, gave a fairly straightforward set of least-cost, least-risk resource portfolio options to being inextricably intertwined with discrete policy choices (some of which have large effects). While past IRPs had to address some state-specific resource decisions, the scope of those decisions rendered them relatively easy to isolate. Projects like Black Cap Solar and Utah's Subscriber Solar required simple accommodations. These newer state policies are significantly different, and in many cases have been supported in legislatures by the Company's advocacy. The IRP has been altered, as the Company has described on its IRP webpage (emphasis added):[149]

> The IRP uses system modeling tools *as part* of its analytical framework to determine the long-run economic and operational performance of alternative resource portfolios. These models simulate the integration of new resource alternatives with our existing assets, thereby informing the selection of a preferred portfolio judged to be the most cost-effective resource mix *after* considering risk, supply reliability, uncertainty, and *government energy resource policies*.

At the beginning of this section, the Division referenced one of Utah's IRP guidelines:

> The Commission finds that the jurisdictional needs of Utah will be a primary consideration in the Commission's evaluation of the Company's

[147] 2021 IRP, Volume I, p. 49.
[148] 2021 IRP, Volume II, p. 60.
[149] https://www.pacificorp.com/energy/integrated-resource-plan.html/ (emphasis added).

> IRP. However, where possible and when minimal impact on Utah's interests exists, coordination with other jurisdictions will be pursued.[150]

Given the significance of recent Oregon and Washington state mandates, the impact on Utah's interests could be significant. It is difficult to envision a 2023 IRP where IRP guidelines can be met in a single integrated plan that is not disruptive to Utah ratepayers. In a system where states set different policies for their energy supplies, it is likely to become increasingly harder to ensure states are solely responsible for the unique costs their policies impose, no matter the intent of the Company and the states. The Division does not suggest that the Company should not be shifting its resource choices, reducing emissions, or pursuing many of the goals embodied in the legislation mentioned. Indeed, the Company must consider these factors for a variety of reasons as part of its evaluation of the public interest. Nevertheless, each state will have its own views of how best to evaluate those factors, what resource choices that evaluation will yield, and the pace of change.

This 2021 IRP shows that the Company's consideration of portfolios for IRP modeling is likely to be influenced by some state policies before any modeling is done. Even were that not the case, tracking different IRP portfolios through an action plan, subsequent IRPs, resulting resource procurement processes, and into rates will be effectively impossible. This makes it likely that states in the Company's system will pay some costs, and receive some benefits, for policies their state has not adopted. It also highlights the importance of the Company making some basic, less-judgmental modeling efforts that can serve as a better baseline to evaluate the effects of policy choices.

9. Solutions and Recommendations

The Division proposes the following solutions to ensure that the IRP is filed on time in the future, with adequate input from stakeholders. While some of these solutions are more prescriptive than the Commission has generally been in the IRP process, the existing flexibility

[150] *Standards and Guidelines*, p. 16.

has eroded the process and its ultimate product in recent years. Additional standards are warranted.

Solution #1: The Company needs to update its Supply Side table for natural gas plants so that as inputs, the model has current costs and operating characteristics. While the Company included the Burns & McDonald table in the 2021 IRP (even though it didn't use it), the table has not been updated since the 2019 IRP. The model's output is only as good as the inputs that go into it. The Commission should order the Company to update its Supply Side Resource Table for natural gas resources before the 2023 IRP and must be required to let the Plexos model have the option of selecting natural gas proxy resources to see what would have been chosen but for state-specific energy policies.

Solution #2: As just described, the Company needs to let the model perform its system optimization first to see what resource portfolio selections are analytically determined to be the least-cost, least-risk set portfolio of resources, with a set of assumptions and inputs common across all jurisdictions, prior to other state-specific constraints. The idea is to identify, as near as possible, a policy-agnostic portfolio of proven resource types that represents the least cost, least risk set of resources. As in past IRPs, the Company had nine price-policy scenarios made up of low, medium, high gas and electricity prices and no, medium, and high carbon prices. The Company should continue these nine price policy scenarios, without the social cost of greenhouse gas as one of the price-policy inputs to the modeling. If the Company is including the SCGHG measure, as it appears it is mandated to by Washington and Oregon, then the SCGHG should be modeled in addition to the other nine price-policy scenarios, so that we end up with at least nine price policy scenarios that include no SCGHG. Then, if the Company decides to include that measure in all the other price policy scenarios, the Company should end up with a larger matrix of possibilities, with no/low SCGHG, medium SCGHG, and high SCGHG as price-policy inputs. From this baseline, other policy options, more nascent technologies, and other options can be judgmentally added or subtracted to more fully evaluate what planning period conditions might require.

After the Plexos ST modeling has determined a first-run system optimization of resource portfolios, the Company can explain and justify any other hard-coded changes to the Plexos modeling it intends to implement and stakeholders should be apprised of this decision beforehand. This is necessary for the Commission to determine what the true costs and risks of alternative scenarios are before accounting for other state energy policies. It could very well be that the preferred portfolio selection after accounting for other state energy policies is the portfolio that also is in the public interest under Utah law, but without the analytical process described above, it is impossible to make this determination. Coming after the initial modeling recommended, this later, more judgmental exercise will more fully reveal the choices to be made, when they must be made, and what is forcing those choices. A better, fuller IRP will result.

Solution #3: The Commission should order the Company to provide meeting materials at least three business days in advance of each meeting, to allow stakeholders to thoroughly review materials prior to the meetings.

Solution #4: The Company should be required to file its *complete* IRP on March 31 of each odd year. Parties need the data discs that contain the analytics to study and analyze the IRP. The Commission has not granted permission for the Company to file the heart of the IRP (the data discs) two weeks late, which the Company has tended to do over the past several IRP cycles. Even with the five-month extension, the Company did not file a complete IRP until September 15, 2021. The Commission should also be wary of future requests for extensions and the claim that the delay will enable fuller participation. Experience does not support that claim.

Solution #5: The Company should revert to its previous norm of filing a draft IRP on or around February 1, so that parties can have a meaningful opportunity to make comments and requests for sensitivities on the preferred portfolio. The Company should then file its final IRP on March 31 of every odd year and its IRP Update on March 31 of every even year.

Solution #6: Hire additional personnel. The Division participates in many Company matters, including the Multi-State Process (MSP), and meeting materials are usually sent to participants in advance. The Division wonders whether PacifiCorp's IRP team has adequate staffing to support the IRP. The Division recommends that the Company conduct an internal analysis to determine how many employees work in each function of the IRP and determine how many additional employees it would require to complete IRP processes on time. Attention should be paid to what other efforts draw IRP personnel away from IRP tasks. The Division suggests the Company consider assigning a specifically dedicated employee to creating meeting materials and ensuring that: (1) IRP meetings dates are planned months in advance; (2) meeting invitations are sent weeks in advance of meetings; and (3) Meeting materials are emailed to the distribution list at least three business days in advance of each meeting.

If the Company does not have enough people who work strictly with the Plexos model, the internal review should determine how many additional full-time employees (FTE) are needed to complete the modeling work on time so that meetings are not cancelled. The internal review should also ensure that the Company has dedicated technical writers to prepare the IRP slides, and FTEs who can be writing the draft IRP while others are completing remaining analytical work on the IRP. Whether due to labor market issues, cost-containment actions, or something else, it appears the Company has insufficient numbers of personnel to meet its requirements. The Division suggests this review happen as soon as possible, so that adequate employees can be added to the IRP team before the 2023 IRP process begins in earnest.

Solution #7: To facilitate stakeholder discussion and public input, the Commission should order the Company to generally conduct full, two-day meetings as it has done in the past. This position could be the default, with other meeting options available as needed and approved by the Commission in an IRP order.

Solution #8: With respect to Stakeholder Feedback forms, the Commission should order the Company to provide the date it answers each Stakeholder Feedback item. The Division notes that the Company rarely provided responses on the dates it had originally anticipated. Missed deadlines should be an occasional exception, not common practice.

Solution #9: Public input meetings should be recorded and posted to the Company's IRP webpage, so that when the Company cancels or reschedules meetings, stakeholders will still have access to view the meeting. This would also obviate the need for some participants to have to travel to Salt Lake City or to Portland to attend meetings (if in-person meetings are re-instituted post-Covid). The Division has found virtual IRP meetings to be the preferable approach to IRP meetings for most purposes. More questions and answers are addressed in this format, since participants must raise their hand or type a comment in the chat box. Also, everyone can view the stakeholders' questions, whereas on the television monitors, it has been difficult in the past to hear questions from the television monitors.

10. Conclusion

The Division appreciates the work that the Company has performed for this IRP and recognizes that a multi-state IRP is very difficult to create. However, issues regarding the timing of the IRP filing, the scheduling of meetings, and when meeting materials are distributed have continued to plague the IRP process. These issues occurred in the 2017 and 2019 IRPs and continued throughout the 2021 IRP, and so we recommend several solutions for these problems. The Division also believes that the modeling should be able to select natural gas resources[151] on par with other resources, so that implications of state policies can be more clearly seen. The Division's proposed solutions on these and other issues should help ensure that the IRP process works as intended, and that stakeholder input can inform the Company's IRP.

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[151] While in this IRP the issue concerns natural gas plants, the general principle applies to more than just natural gas. Proven resource types of whatever kind should not be excluded in advance from initial modeling runs. They can be judgmentally evaluated after initial runs identify a more agnostic baseline.