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COMMENTS ON PACIFICORP'S 2017 IRP

To: Utah Public Service Commission

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Date: October 24, 2017

Subject: Docket No. 17-035-16, PacifiCorp's 2017 Integrated Resource Plan

RECOMMENDATION (DO NOT ACKNOWLEDGE)

The Division of Public Utilities (Division) recommends that the Public Service Commission (Commission) not acknowledge PacifiCorp's (Company) 2017 Integrated Resource Plan (IRP) and accompanying Action Plan. As explained below, the Division finds the 2017 IRP grossly ignores the Commission's core IRP-defining principles and procedures and does not comply with its authoritative Standards and Guidelines.[1] These are included with this filing as Attachment A.

BACKGROUND

On April 4, 2017, PacifiCorp filed its 2017 IRP pursuant to the Commission's 1992 Report and Order on Standards and Guidelines for Integrated Resource Planning in Docket No. 90-2035-01. This docket was opened on March 20, 2017, when the Company filed a request for a four-day extension of time to file the IRP on April 4, 2017 rather than March 31, 2017 (the due date). The Commission granted the extension, and on April 4, 2017, the Company filed its cover letter and Volumes I and II to the IRP in readable or print view layout. On April 11, 2017, the Company filed the work papers and data files contained in the IRP.[2] In its cover letter the Company requests that the Commission acknowledge the 2017 IRP and fully support the 2017 IRP conclusions, including the Company's proposed Action Plan.[3]

On April 20, 2017, the Commission convened a Scheduling Conference that resulted in the Commission's April 25, 2017 Scheduling Order and Notice of Technical Conference in this matter. The Commission conducted a Technical Conference on June 19, 2017. In addition to scheduling the Technical Conference, the Commission requested that interested parties file IRP comments on or before October 24, 2017, with reply comments due on or before December 15, 2017.

Approximately six months after the IRP due date, on August 2, 2017, the Company filed with the Commission its "RMP Informational Filing" that contains "an updated economic analysis and related discussion on its proposed wind repowering and new transmission and wind projects included in the 2017 IRP."[4] The Company refers to these three projects as its Energy Vision 2020--which is the heart of the Company's 2017 IRP and IRP Action Plan.

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[1] Docket No. 90-2035-01, Report and Order on Standards and Guidelines, June 18, 1992.
[2] By filing the contents of the IRP on April 11, 2017, the Company was actually 11 days late, rather than the requested four days.
[3] PacifiCorp's 2017 IRP Cover Letter, April 4, 2017.
[4] PacifiCorp's 2017 IRP Informational Filing Cover Letter, August 2, 2017.

In response to the Commission's request for comments, the Division provides the following IRP comments, with a focus on the Company's proposed $3.5 billion near-term acquisitions that were developed late in the IRP process away from other participants in the process, as well as the 2017 IRP Action Plan, and on the Company's failure to adhere to the Commission's Standards and Guidelines. The Division provides recommendations to the Commission on suggestions to preserve the integrity of the role of electric resource planning that serves the long-term public interest of Utah ratepayers. It is the Division's hope and goal that the lessons learned from the Company's failings in this IRP help avoid similar shortcomings in future IRPs in Utah. The Division requests that the Commission implement directives suggested herein in an attempt to improve transparency, encourage the free flow of information, and to respond to and share with others the stakeholder feedback submitted to the Company. The Division hopes these measures, as well as other recommendations will help the Company manage its IRP in a more effective manner.

As a preliminary matter, the Division commends the Company for its efforts to produce this system-wide IRP in the context of a changing regulatory environment with rapidly advancing and emerging technologies affecting all aspects of long-term electric utility planning. The Division thanks the Company for responding to data requests and for hosting public stakeholder meetings. The Division commends the stakeholders who have actively participated in general meetings and appreciates parties who have provided feedback and constructive comments to the Company in the development of this IRP. Unfortunately, as will be discussed later, the Company's responses to the majority of the stakeholder comments were not shared with other stakeholders as promised. Other deficiencies also infected the ultimate filed IRP.

ENERGY VISION 2020

Central to the Company's IRP and Action Plan is the $3.5 billion Energy Vision 2020 plan--a near-term investment of enormous magnitude and scope that the Company states must be completed by the year 2020 for it to be economical. It should be noted that all $3.5 billion of the proposed Energy Vision 2020 projects were selected by the Company to be in its 2017 IRP Preferred Portfolio and equally alarming is that they are proposed as near-term action items in the Company's 2017 IRP Action Plan.

The Action Plan lays out actionable items the Company must make in the near-term to implement its Preferred Portfolio.[5] Given the near-term (one could argue past-term), [6] acquisition of resources of this magnitude and scope, the Action Plan items related to Energy Vision 2020 are of paramount concern.

The Division is particularly concerned with the following key Action Items: 1a (wind repowering), 1b (new wind), 2a (new transmission from Aeolus to Bridger/Anticline) and 2b (continued permitting of Energy Gateway segments). The fact that the Company had previously identified no need for the new resources, but instead presents these acquisitions as ***purely economic decisions***, means that the regular IRP standards for review may not be relevant, as system need is an essential element of that review standard. At a minimum, the connection between need and the Energy Vision 2020 projects is less apparent than the tie between need and resource acquisitions in past planning activities.

<u>Wind repowering</u>. This includes repowering 999 megawatts[7] (most of the Company's entire existing wind fleet) with new equipment. The Company's wind repowering entails upgrading its wind facilities by installing new rotors with longer blades and new nacelles with higher-capacity generators. The Company estimates that the improvements will increase generation by 13 to 35 percent when compared to its existing infrastructure. The Company is asking the Commission to acknowledge in its IRP Order the repowering of nearly the entire wind fleet that has taken more than a decade to originally and individually acquire. The acquisition of these existing wind projects was reviewed as part of general rate cases or major plant additions,

[5] Docket No. 17-035-16, PacifiCorp's 2017 Integrated Resource Plan, April 4, 2017, pp. 266-269.
[6] The Company states that it had already purchased the wind turbine equipment in December of 2016. (See Docket No. 17-035-39, Direct Testimony of Mr. Timothy J. Hemstreet, p. 4, lines 90-92.
[7] Docket No. 17-035-16, RMP's Informational Filing, August 2, 2017, p. 2.

but not in the context of an IRP. Integrated resource planning involves long-term resource planning where acquisitions are traditionally made to meet a load or capacity deficit.

The Division has copied the relevant sections of the Company's Action Plan below that address the Company's plans to move forward with its near-term Energy Vision 2020 resource decision. The Division believes that these action items should not be acknowledged.[8] The wind repowering is found in Action Item 1a of the 2017 IRP Action Plan:

Renewable Resource Actions

<u>Action Item 1a. Wind Repowering</u> PacifiCorp will implement the wind repowering project, taking advantage of safe-harbor wind-turbine-generator equipment purchase agreements executed in December 2016.
▪ Continue to refine and update the economic analysis of plant-specific wind repowering opportunities that maximize customer benefits before issuing the notice to proceed.
▪ By September 2017, complete technical and economic analysis of other potential repowering opportunities at PacifiCorp wind plants not studied in the 2017 IRP (i.e., Foote Creek I and Goodnoe Hills).
▪ Pursue regulatory review and approval as necessary.
▪ By May 2018, issue the engineering, procurement, and construction (EPC) notice to proceed to begin implementing the wind repowering for specific projects consistent with updated financial analysis.
▪ By December 31, 2020, complete installation of wind repowering equipment on all identified projects.

[8] Id. at pp. 265-266.

Wind Request for Proposals. In addition to wind repowering, the Company's Preferred Portfolio includes up to 1,100 megawatts of new wind resources with a commercial operation date of no later than December 31, 2020, that are capable of interconnecting with PacifiCorp's transmission system if the wind is located in Wyoming.[9]

Renewable Resource Actions

Action Item 1b. Wind Request for Proposals PacifiCorp will issue a wind resource request for proposals (RFP) for at least 1,100 MW of Wyoming wind resources that will qualify for federal wind production tax credits and achieve commercial operation by December 31, 2020.
▪ April 2017, notify the Utah Public Service Commission of intent to issue the Wyoming wind resource RFP.
▪ May-June, 2017, file a draft Wyoming wind RFP with the Utah Public Service Commission and the Washington Utilities and Transportation Commission.
▪ May-June, 2017, file to open a Wyoming wind RFP docket with the Public Utility Commission of Oregon and initiate the Independent Evaluator RFP.
▪ June-July, 2017, file a draft Wyoming wind RFP with the Public Utility Commission of Oregon and file a Public Convenience and Necessity (CPCN) application with the Public Service Commission of Wyoming.
▪ By August 2017, obtain approval of the Wyoming wind resource RFP from the Public Utility Commission of Oregon, the Utah Public Service Commission, and the Washington Utilities and Transportation Commission.

[9] The Division notes that there are currently two pending dockets open before the Commission requesting approval of a resource decision to repower its wind in Docket No. 17-035-39 and for a resource decision for the new wind and transmission in Docket No. 17-035-40. The Company is requesting a combined pre-approval of approximately $3.5 billion in project costs. There is also a related RFP docket open in Docket No. 17-035-23 and in Oregon Docket UM-1845.

▪ By August 2017, issue the Wyoming wind RFP to the market.
▪ By October 2017, Wyoming wind RFP bids are due.
▪ November-December, 2017, complete initial shortlist bid evaluation.
▪ By January 2018, complete final shortlist bid evaluation, seek acknowledgement of the final shortlist from the Public Utility Commission of Oregon, and seek approval of winning bids from the Utah Public Service Commission.
▪ By March 2018, receive CPCN approval from the Wyoming Public Service Commission.
▪ Complete construction of new wind projects by December 31, 2020.

The Company requests that the Commission acknowledge the repowering of almost all of its current wind fleet, as well as up to 1,100 megawatts of new wind projects (new wind), plus the completion of transmission network upgrades and the construction of the 140-mile, 500 kV Aeolus-to-Bridger/Anticline transmission line, known as Energy Gateway Sub-segment D2 (Segment D or transmission line). The new wind and transmission projects are offered together or not at all. The transmission actions are found in Action Item 2a through 4b. The near term Action items of primary concern are those found in Items 2a and 2b respectively:

Transmission Actions

<u>Action Item 2a. Aeolus to Bridger/Anticline</u> By December 31, 2020, PacifiCorp will build the 140-mile, 500 kV transmission line running from the Aeolus substation near Medicine Bow, Wyoming, to the Jim Bridger power plant (a sub-segment of the Energy Gateway West transmission project). This includes pursuing regulatory review and approval as necessary.

▪ June-July 2017, file a CPCN application with the Public Service Commission of Wyoming.
▪ By March 2018, receive conditional CPCN approval from the Wyoming Public Service Commission pending acquisition of rights of way.
▪ By December 2018, obtain Wyoming Industrial Siting permit and issue EPC limited notice to proceed.
▪ By April 2019, issue EPC final notice to proceed.
▪ Complete construction of the transmission line by December 31, 2020.

Action Item 2b. Energy Gateway Permitting[10] Continue permitting for the Energy Gateway transmission plan, with the following near-term targets:
▪ For Segments D1, D3, E, and F, continue funding of the required federal agency permitting environmental consultant actions required as part of the federal permits.
▪ For Segments D, E, and F, continue to support the projects by providing information and participating in public outreach.
▪ For Segment H (Boardman to Hemingway), continue to support the project under the conditions of the Boardman to Hemingway Transmission Project Joint Permit Funding Agreement.

[10] Action Item 2b will be discussed later in the Division's comments under Energy Gateway modeling.

The Company has presented a package proposal that, without a clearly-defined need for the resources, is difficult to consider the least cost, least risk portfolio given the following considerations: the actual production tax credits (PTCs) may not be realized as expected, the individual PTCs may not be as valuable as expected, there may not be as many PTCs generated as expected, the projects may experience cost overruns or project delays, and energy prices may be lower than anticipated.[11] Other risks exist too. The Company claims its action items are least-cost, based on the Company's stochastic present value revenue requirement (PVRR) portfolio analysis. The Company's calculations yield minor economic benefits, but only under a limited range of conditions.

The Company acknowledges that the new wind and transmission project would most likely not be economic if natural gas prices stay low through 2036 and that the new wind and wind repowering projects are uneconomic without the PTCs. The Company has two open dockets in Utah that plainly state that neither the wind repowering nor the wind and transmission projects are economic without 100 percent of the PTCs. In Docket No. 17-035-39, the Company writes the following[12] (emphasis added):

> For these 32 wind turbine locations, the higher retained value of the foundations means that repowering, while technically feasible, would not qualify those turbines for PTCs, *which is necessary for the repowering to be economic*.

In Docket No. 17-035-40, with respect to the new wind and transmission, the Company writes the following[13] (emphasis added):

[11] [11] Docket No. 17-035-40, Application for Approval of a Significant Energy Resource Decision and Voluntary Request for Approval of Resource Decision. June 30, 2017, p 5.
[12] Docket No. 17-035-39, Direct Testimony of Timothy J. Hemstreet, June 2017, pp. 8, lines 169-171.
[13] Docket No. 17-035-40, Application for Approval of a Significant Energy Resource Decision and Voluntary Request for Approval of Resource Decision. June 30, 2017, p 5.

> ***The economics of the Combined Projects rely on PTCs***, the Company must complete all construction by the end of 2020 to fully qualify for the PTC benefit.

The Division recognizes these projects for what they are: opportunistic ventures that might be modestly beneficial to ratepayers if a host of risks do not come to pass. The Company committed significant funds for these projects last year, before its IRP analysis showed them to be necessary. The Company now asks the Commission to acknowledge its resource decision in the context of an IRP proceeding, nearly eight months after the Company's acquisition of wind facilities. The $3.2 billion of Energy Vision 2020 projects could remain in rate-base for decades earning the Company a return, while ratepayers would be paying for resources that may not be needed, may not be least-cost, and likely are not the least-risk resources available to meet load. The Division recommends that the Commission not acknowledge any of the Action Items associated with the Energy Vision 2020 plan.

THE IRP IS A LEAST-COST, LEAST-RISK PLANNING TOOL THAT IS BASED ON A RESOURCE NEED, NOT AN ECONOMIC OPPORTUNITY.

The Division recommends that the Commission not acknowledge the 2017 IRP because the Company did not meet the Standards and Guidelines by including resources that are not based on a resource need, traditionally understood. The Commission does not acknowledge actions to meet a need that has not been clearly identified or defined. The Standards and Guidelines define the IRP as a process to evaluate all known resources on a consistent and comparable basis, ***in order to meet current and future customer electric needs*** at the lowest total cost to the utility and its customers.[14] While the Energy Vision 2020 projects are designed to meet a need in the sense that the electrons produced will be part of a portfolio meeting RMP's customers' loads, the need for them did not arise from the traditional analysis of capacity and energy adequacy.

[14] Docket No. 90-2035-01, Report and Order, June 18, 1992, p. 18.

By the end of 2016, the Company completed the IRP public input process and produced a draft Action Plan. The draft Action Plan showed no new resource acquisition because the Company's load and resource balance analysis showed ***no projected need*** for additional resources to reliably serve the system load. The Company's capacity balance indicated that both summer and winter margins[15] were projected to be in excess of the 13 percent planning margin over the next decade.[16] Even now, after its post-public input revisions, with respect to energy balance, the Company states that it will not have an energy shortfall during off-peak hours until the year 2026 and only a small projected short-duration on-peak energy shortfall in 2022.[17] The lack of actual need for additional resources is also evidenced by the fact that the next natural gas resource is not added until the year 2029, one year later when compared to the Company's 2015 IRP.[18]

However, at the very end of the IRP process after committing funds to Energy Vision 2020 projects and after the public input process, the Company drastically changed its Action Plan to include the wind repowering and the new wind and transmission projects. The driver of the wind repowering and the new wind and transmission projects is ultimately the economic opportunity associated with PTCs.[19] The Company claims that repowering its wind fleet by 2020 will allow the Company to capture 100 percent of available PTC benefits. The Company's request for acknowledgement of the new wind and transmission is based on that economic opportunity, not a capacity or reliability need that was otherwise identifiable.

The Company has repeatedly claimed that these resources are not being added to the system to meet a regulatory requirement such as Renewable Portfolio Standards (RPS) compliance, but states that they may be used to contribute towards meeting future RPS compliance needs. The Division recommends that the Commission should be vigilant in protecting Utah ratepayers against any increase in rates directly due to costs of resources

[15] The Company added a winter load and resource balance for the 2017 IRP, see Table 1.3, p. 11.
[16] Docket No. 17-035-16, PacifiCorp's 2017 Integrated Resource Plan, April 4, 2017, pp. 10-11.
[17] Id.
[18] In. at p. 2.
[19] Id. at pp.1-2.

acquired solely to meet other state policy requirements that are not least-cost resources. The Commission should also be cautious about the indirect effects on the Company's system of additional renewable resources and should protect Utah ratepayers from subsidizing these investments. The Commission's Standard and Guidelines state the following:[20]

> 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.

The Division noticed two significant changes in the Company's 2017 IRP. The Division observes that the Company has appeared to, on its own accord, modify the traditional and Commission-approved role of least-cost planning. The Commission has issued no guidance or changes to the Standards and Guidelines. However, the Company insinuates that the role of the IRP is not its traditional role as described above: finding a need, determining the least-cost, least-risk portfolio of resources to fill that need, etc. Instead the Company has proclaimed that the IRP's role is to move to a cleaner energy future and/or to decarbonize the system. These may be laudable goals and risk-based analysis may favor such a transition, but the IRP's primary purpose is not to implement such goals.

The Company has assumed away the traditional and Commission-approved need-based IRP objective with the Company's asserted objective to fit its own resource decisions or to support its near-term rate-base investments to justify its $3.5 billion Energy Vision 2020 acquisitions. The Company repeatedly states a new objective to replace the need-based planning objective as follows:

> In the 2017 IRP, PacifiCorp presents a *cost-conscious plan* to *transition to a cleaner energy future* with near-term investments in both existing and new renewable resources, new transmission infrastructure, and energy efficiency programs.[21]

[20] Docket No. 90-2035-01, Report and Order, June 18, 1992, p. 16.
[21] PacifiCorp's 2017 IRP, April 4, 2017, p. 1.

> The 2017 IRP preferred portfolio reflects a *cost-conscious transition to a cleaner energy future*.[22]
>
> . . . PacifiCorp selected a preferred portfolio reflecting a *cost-conscious plan* to *transition to a cleaner energy future* with near-term investments in both existing and new renewable resources, new transmission infrastructure, and energy efficiency programs.[23] (p.179)
>
> The 2017 IRP preferred portfolio reflects a *cost-conscious transition to a cleaner energy future*.[24]

The 2017 IRP does not identify any Utah state policy supporting the Company's proposed "transition to a cleaner energy future" or decarbonizing the future. In fact, there is no unmet Utah state RPS requirement or other policy directive that would justify spending $3.5 billion in renewable resource acquisitions to meet Utah policy requirements. This is in direct opposition to the Standards and Guidelines previously quoted, but worth repeating here: "The Commission finds that the jurisdictional needs of Utah will be a primary consideration in the Commission's evaluation of the Company's IRP."[25]

The Company states on its IRP webpage the following (emphasis added):[26]

> *Since resource decisions can have significant economic and environmental consequences, conducting this planning with transparency and full participation from the regulatory agencies and other interested and affected parties is essential*.

Evidently, the transparency and participation it aspires to were not necessary in developing the Energy Vision 2020 projects. While the projects might conceivably be part of the least cost, least risk portfolio needed to meet future load, the ratepayer risks relative to the purported economic

[22] Id. at p. 2.
[23] Id. at p. 179.
[24] Id. at p. 233.
[25] Docket No. 90-2035-01, Report and Order, June 18, 1992, p. 16.
[26] www.pacifcorp.com/irp.

benefits appear too high, especially given the Company's earlier professions that no additional resource need existed, given available and affordable front office transactions.

THE BAIT AND SWITCH

In this IRP cycle, the Company hosted a June 13, 2016, Utah parties meeting. In addition, the general IRP process included the following scheduled stakeholder meetings,[27] only *five* of which were actually held:

1. June 21, 2016 Kick-Off Meeting
2. July 20, 2016 General Meeting
3. August 25-26, 2017 General Meeting
4. September 22-23, 2016 General Meeting

   October 20-21, 2016 General Meeting – *canceled and rescheduled to December 15-16, which was also canceled*

   *November 17, 2017 – a one hour phone call was held to discuss two items: an updated capacity contribution study and the Official Forward Price Curve Scenarios = < 1 hour

   December 15-16, 2016 General Meeting – *canceled on December 12 (see comments below from parties who had booked flights to attend the meeting)*

   February 23-24, 2017 General Meeting – *canceled*
5. March 2-3, 2017 General Meeting

The Division participated in all of the above general and Utah stakeholder meetings. The Division as well as many other stakeholders and interested parties (listed on pages 57-58 of

[27] The meeting start times all begin at 10:00 a.m. M.T. with a half hour lunch break, and the meetings ended at approximately 5 p.m. on the first day = 6.5 hours. In the cases where the meetings were scheduled for two consecutive days, for the most part, the presenters rushed through hundreds of pages of slides in the first day so that the meetings usually ended early on the second day around noon or shortly thereafter (a Friday) = < 4 hrs. The two-day meetings averaged 6.5 + 4 = 10.5 hours, but were definitely not 16 hours of meeting time as the Company intimates.

PacifiCorp's 2017 IRP, Volume II) were actively participating in this planning process through September, not knowing that we would not have the next general meeting until ***six months later***.

Meanwhile, for those of us who had been following the stakeholder IRP process, the Company produced a draft Action Plan that reflected no resource acquisitions, as the Company's modeling analysis showed that there was ***no projected need*** for capacity until 2028.[28] The Company's filings, workshops or statements in other jurisdictions have also been clear that PacifiCorp's system remains in a state of resource adequacy without new major resource acquisitions.[29]

In hindsight, the Division can see why the Company kept rescheduling and canceling meetings. The Company, as of May of 2016, was working with GE International and Vestas on wind repowering, and in November had completed its own side analysis of wind repowering, in fact making wind turbine generator purchases in the millions of dollars in December of 2016.[30] It was approximately six months later at the March 2, 2017, General Meeting when the Company notified stakeholders that it had already purchased the wind equipment facilities last year and that it had an entirely different Action Plan than the one produced by the Company's modeling analysis that was presented to stakeholders in draft resource portfolios.

The new resource portfolios the Company selected on its own during the six month period (where meetings were repeatedly canceled) and at the end of the IRP process included all of the proposed Energy Vision 2020 projects, stunning the Division as well as most stakeholders. It was at the March 2, 2017 meeting when the majority of active stakeholders were notified that the Company had forged forward on its own divergent path, pursuing opportunistic purchases of equipment months in advance, while the rest of us were working in good faith on what we thought was an open and transparent IRP process.

[28] PacifiCorp General Meeting Presentation, March 2-3, 2017, pp. 4-5.
[29] Oregon LC 67, Statements of PacifiCorp representatives at the September 14, 2017 Special Public Meeting; also see UM 1802 - PAC/300, MacNeil/21.
[30] Docket No. 17-035-39, Direct Testimony of Timothy J. Hemstreet, June 2017, p. 23, lines 500-506.

PUBLIC INPUT PROCESS CONCERNS

Based on the above, the Division makes an obvious finding that the Company not only did not meet, but paid no tribute to, the Commission's Standards & Guideline #3 that states that **"PacifiCorp will provide ample opportunity for public input and information exchange during the development of its Plan."[31]**

Within the published IRP and on PacifiCorp's IRP webpage, the Company makes repeated claims that are false and should be taken down from its IRP page and corrected in its 2017 IRP Update. As an example, on the Public Input Process page, the Company writes the following (emphasis added):[32]

> The public has been involved in PacifiCorp's resource plans from the earliest stages and ***at each decisive step***. Participants have both shared comments and ideas, as well as received information.
>
> The cornerstone of the public input process has been ***full-day meetings throughout the yearlong plan development period***. These meetings have been held jointly in two locations, Salt Lake City and Portland, using telephone and videoconferencing technology, to encourage wide participation while minimizing travel burdens and respecting everyone's busy schedules.
>
> PacifiCorp has pursued an open and collaborative approach to involve state regulatory agencies, customers and other stakeholders in our Integrated Resource Plan development. Since resource decisions can have significant economic and environmental consequences, ***conducting this planning with transparency and full participation from the regulatory agencies and other interested and affected parties is essential***.[33]

[31] Docket No. 90-2035-01, Report and Order, June 18, 1992, p. 42.
[32] http://www.pacificorp.com/es/irp/pip.html.
[33] www.pacificorp.com/irp.

As previously stated, the Division and other stakeholders were left in the dark for approximately six months while the Company conducted sensitivity studies one after another until it arrived at the results that show its $3.5 billion acquisitions were justified. With respect to the full-day meetings throughout the year, the Division states that this is not true by any stretch of the imagination. Below the Division notes the five general meetings that were held, as well as average times for one- and two-day meetings. This does not include the Utah parties' only meeting or the Commission's ordered Technical Conference.

2017 IRP Public Stakeholder Meetings*	
Date	Time allotted
June 21, 2016	6.5 hours
July 20, 2016	6.5 hours
August 25-26, 2017	10.5 hours
September 22-23, 2016	10.5 hours
March 2-3, 2017	10.5 hours
Total Time	**44.5 hours**
*The meeting start times all begin at 10:00 a.m. M.T. with a half hour lunch break, and the meetings ended at approximately 5 p.m. on the first day = 6.5 hours. In the cases where the meetings were scheduled for two consecutive days, for the most part, the presenters rushed through hundreds of pages of slides in the first day so that the meetings usually ended early on the second day around noon or shortly thereafter (a Friday) = < 4 hrs. The two-day meetings averaged 6.5 + 4 = 10.5 hours, but were definitely not 16 hours of meeting time as the Company intimates.	

Although this year was worse than previous years with respect to scheduling and time management, the Company has consistently kept stakeholders out of the process for months at a time, as the Company has claimed it needed the time to run its models. It is usually during this time when final screening steps are altered, new assumptions are updated, or many other surprises to rankings, screening methods, etc. take place that stakeholders only learn about when the Company provides us with its preferred portfolio. While the models are running the Company could use this time to present the strategically aligned Company's 10-year Business Plan. This time could also constructively be used to discuss in depth third-party consultant reports, meetings of the Technical Review Committee, the Smart Grid study, Flexible Resource Capacity, or a myriad of other topics that are barely touched on in meetings.

Since the Company's lack of transparency and barring stakeholder meetings for months at a time has transpired for so many years and has escalated to possibly the Company's poorest public input process in the 2017 IRP, the Division believes the Commission needs to take a more active-directive role in requiring the Company to meet its Standards & Guidelines, especially with respect to threshold and foundational issues such as process management (although there are many other areas where the Company fell short in this IRP).

With respect to the five General Meetings that did take place, the Company claims the meetings have been ***full-day meetings throughout the year-long plan development period***. As pointed out previously, none of the meetings were full-day meetings (8 hour workday meetings). In fact, the majority of the meetings were at best three-quarters of a day. Where a second day was scheduled for meetings, the agenda was often times rushed so quickly the first day in order to get out early on the second day—a Friday. In one instance the Company rushed through a PowerPoint deck of 106 slides on the first day of the meeting. The meeting topics were difficult, complex, and highly technical. Stakeholders that did come back the second day were left to cover approximately 40 slides[34] so the meeting could adjourned early. This displays poor planning and poor time management.

Where meetings were canceled, such as the December 15-16, 2016 general meeting, the Company notified stakeholders on December 12, after many had already arranged flights and hotels.[35] The Division refers the Commission to Attachment B to this document, Stakeholder Feedback Form of the Sierra Club, submitted on January 19, 2017.

[34] August 25-26, 2016 IRP General Meeting Presentation. http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/PacifiCorp_2017_IRP_PIM03_8-25-2016_to_8-26-2016.pdf

[35] See Stakeholder Feedback Form, Sierra Club, submitted on January 19, 2017.

The Division's concern is not so much with getting out early from a meeting, but rather the complexity and number of topics that must be addressed, given only five days to cover a massive agenda of outside studies, inputs, IRP assumptions, supply side resources, Demand Side Management (DSM) potential study, portfolio development, stochastic modeling, front office transactions (FOTs), planning reserve margin, private generation, load forecast, load and resource balance, etc. One need only look at the Table of Contents in the two respective volumes of the IRP to see the depth and breadth of topics encompassed in long-term resource planning. The Table of Contents in Volume 1 encompasses 14 pages, and the Table of Contents in Volume 2 contains 11 pages. Together the IRP Volumes 1 and 2 total 577 pages—an ambitious amount of topics to cover in five short meetings. This does not include the four data discs of files that stakeholders are left to comb through individually.

Procedural Issue #2: Information Exchange is the most reasonable method for developing and implementing integrated resource planning in Utah.

- The Division recommends that the Commission order the Company to hold monthly, two-day (6-8 hour day) meetings through the "yearlong development period" and at "each decisive step" of the IRP process.

The Division recommends that the Company schedule in December a General Meeting whereby the Company and interested parties can draft an agenda that delegates an adequate amount of time each month for the known and usual topics. Some agenda items require greater dialogue, explanation, and questions and answers that can be planned for at this time. Granted there will be always be small deviations from meeting agendas, but this way stakeholders will be informed throughout the process and at each decisive step so that there will be no more "surprise" IRP results.

As part of the merger commitments when MidAmerican Energy purchased PacifiCorp, representatives from the Company's headquarters in Oregon were required to have a presence in

Utah, especially since Utah accounts for more than 40 percent of the Company's electric load. "MEHC and PacifiCorp commit to maintaining adequate staffing and presence in each state, consistent with the provision of safe and reliable service and cost-effective operations."[36]

- The Division recommends that the person in charge of the IRP, its work papers, its modeling software, etc., Mr. Rick Link, be required to attend at least every other or half of the stakeholder meetings in Utah.

The Division recommends that the Company's 2017 IRP conclusions and results should not be acknowledged. Results that are produced from this IRP do not meet the long-term public interest of Utah ratepayers.

STANDARDS AND GUIDELINES

According to the Commission's Standards and Guidelines that have been the foundation for resource planning for decades, by very definition, the Company has obfuscated the meaning of the IRP. As a threshold issue the Commission has defined integrated resource planning as follows (emphasis added):[37]

> Integrated resource planning is a utility planning process which evaluates all known resources on a consistent and comparable basis, in order to meet current and future *customer electric energy services needs* at the lowest total cost to the utility and its customers, and in a ***manner consistent with the long-run public interest***. The process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty.

The Division emphasizes the following two points in the Commission's definition of integrated resources planning: (a) as previously discussed, the foundational finding of need takes

[36] PacifiCorp and MEHC merger commitment 47
[37] Docket No. 90-2035-01, Report and Order, June 18, 1992, p. 41.

primacy in an IRP and (b) the evaluation must be conducted in a manner that is consistent with the long-run public interest. As discussed below, the Company needs to file its complete IRP filing on time in order for parties to be able to fully evaluate the IRP. This was not the case in the 2017 IRP. In the Division's view the public interest also includes the foundational finding that need takes precedence.

It is generally understood that the Commission has the responsibility to promote and protect the public interest. Mr. Scott Hempling provides a definition of public interest[38] that includes the following three attributes: (1) economic efficiency, i.e. "biggest bang for the buck;" (2) sympathetic gradualism, i.e. "smoothing economic efficiency's hard edges;" and, (3) political accountability, which "requires the regulator to create political acceptance of decisions that implement economic efficiency and sympathetic gradualism. Political accountability does not mean caving in to interest groups.[39]"

The Utah Supreme Court has made some citations to the concept of public interest in its decisions regarding the Commission. In White River Shale Oil Corp. v. Public Service Commission of Utah, (May 2, 1985, 700 P.2d 1088, 1985 WL 1083574) in paragraph 7 observed:

> It is undisputed that the PSC has been charged with the responsibility of regulating utilities in the public interest and that it has the necessary expertise to do so. Broad standards such as "reasonable," "unnecessary" and "public convenience and necessity" have been held to be sufficient as standards even though incapable of precise definition.[12] "Public interest" certainly falls within this class of standards and, ***1092** when read in light of the entire Public Utilities Act, is not so broad as to result in an improper delegation of authority.

In Garkane Power Association v. Public Service Commission of Utah (681 P.2d 1196, 1984, paragraph 6) the Utah Supreme Court identified "two essential objectives in the promotion of the public interest":

[38] Scott Hempling, *Preside or Lead? The Attributes and Actions of Effective Regulators*, 2010.
[39] Id. at p. 4.

> First, the Commission must deal with those subject to its jurisdiction in such a manner as to assure their continued ability to be able to serve the customers who rely upon them for essential services and products. Second, the Commission performs the extremely delicate, and not uncontroversial but nonetheless essential, function of balancing the interest of having financially sound utilities that provide essential goods and services against the public interest of having goods and services made available without discrimination and on the basis of reasonable costs.

Further guidance might be found in the statutory obligations of the Division of Public Utilities found in UCA § 54-4a-6.

The second threshold issue the Division calls the Commission's attention to is item #2: **The Company will submit its Integrated Resource Plan biennially.[40]**

The Division and this Commission has a long history of dealing with delays and getting the Company to file IRPs on time.[41] The Company was about five months late from a presumed January filing in Docket No. 07-2035-01. In its 2008 IRP, the Commission had to take an active direct role and ordered the Company to file its IRP on April 8, 2009, after repeated delays, all with unique justifications for the delays.[42] As further historical context, the Company used to file a draft IRP, parties would comment on the draft, the Company would review the parties' draft comments, and then issue a final IRP. The written draft IRP was eliminated because the schedule was so tight that parties that did file draft IRP comments never had those comments acted upon because the final IRP was filed at the same or very close to the same time that the draft IRP comments were coming in from stakeholders.

The Division points out this information to the Commission, not because it believes a four-day delay in the 2017 IRP is a major violation of the Commission's rule to file biennially.

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[40] Id.
[41] Division memo, "In the Matter of the Acknowledgment of PacifiCorp's 2006 Integrated Resource Plan: Docket 07-2035-01 (Filed on May 30, 2007 as "2007 Integrated Resource Plan"), p. 11.
[42] Docket No. 07-2035-01, Order and Notice of Scheduling Conference, April 7, 2009.

However, the Division sees a different type of slippage with respect to the biennial IRP filing. When the Company filed its 2017 IRP on April 4, 2017, it admitted in its cover letter, that it was not filing the contents of the IRP, but that it intended to file the contents on April 11, 2017.[43] As noted previously, this in effective made the IRP 11 days late from its March 31, 2017 filing deadline.

When taking into consideration the fact that the Company did not make its RMP Informational Filing containing the heart of the 2017 IRP until August 2, 2017, approximately four months after the March 31, 2017 filing date, this becomes problematic, especially in light of the fact that the Company caught most stakeholders off guard when the Company notified stakeholders that it had already purchased the wind turbine equipment to be used for wind repowering and that it decided to pursue the "exciting" new wind and transmission package, both part of the Company's Energy Vision 2020, that was filed after the Commission had issued its Scheduling Order in the IRP docket.

- The Division recommends that the Commission require the Company to make a complete filing when it files it March 31 IRP and other than small corrections, the Company must not be allowed to make an entirely separate informational or addendum or other substantive IRP filing that changes the constitution of the Preferred Portfolio or Action Plan without prior permission from the Commission and after showing a demonstrable need to make a new IRP filing

Although the 2015 IRP was filed on April 30, 2015, one month late, one positive outcome of the 2015 IRP filing is that the Company filed its DSM Potential Study on January 30, 2015, as it became available.

- The Division recommends that the Company file the DSM Potential study in the next IRP in January of 2019.

[43] Docket No. 17-035-16, PacifiCorp's 2017 IRP Cover Letter, April 4, 2017.

- The Division also recommends that any outside or supporting studies that are used as inputs to the IRP or as assumptions in the IRP be filed as soon as they become available to the Company. This allows stakeholders the opportunity to take part in each step of the IRP and especially before assumptions are locked in.

- As part of this recommendation, the Division requests that the Commission require the third-party consultant who performed each Company-commissioned study present his or her findings and analysis—not a Company representative, but the author of the outside study. During the 2017 IRP process, the Company had its consultants available on the phone, but it was the Company that reported on the studies, analyses and results of the studies. This is important because the Company may not clearly articulate the primary author's work or know the appropriate response to specific answers.

  This is a repeated request that the Division has made before and requests the Commission direct on an ongoing basis. This also serves the purpose of ensuring *transparency* in the IRP process, such that stakeholders can be assured of the third-party or outside consultant study results—without relying on what the Company interprets the study results and analyses to mean. The Division believes this approach will answer a lot of concerns that stakeholders have had with respect to gas and price forecasts, solar and renewable resource costs and attributes, private generation, energy DSM penetration levels, etc.

- The Division requests that the Commission require the Company to file its outside or supporting studies as they are made available. This applies to not just the DSM Potential Study, but each of the respective studies that are conducted outside of the IRP modeling and brought into the IRP process. As described earlier, it allows stakeholders the opportunities to study the information and ask questions during the process rather than after the matter of the fact when the Company files its final IRP.

- The Division also expressly requests (as we have multiple times in the past) that the Commission ***order*** the Company to file all work papers, studies, inputs, assumptions, or any kind of IRP tables or charts in their native format. The Division has asked repeatedly for files that the Company could have easily been attached in discovery or as part of IRP files in fully executable, native files.

Procedural Item #3: **PacifiCorp will provide ample opportunity for public input and information exchange during the development of its Plan**.

With respect to meeting materials, the Company has failed miserably in this IRP. In the past, the Company agreed to provide meeting materials one week in advance so that stakeholders could have time to read the information and actively participate in the stakeholder meeting where the Company presents the information. At times in this cycle, the Company filed meeting materials as late as 2:00 p.m. M.T. or even after normal business hours, and the Division as well as other parties never had a chance to review the information before the meeting.

- The Division requests the Commission direct the Company to file meeting materials at least one week in advance. Further, the Division has asked for a written narrative from the Company for each topic that it proposed to address at the upcoming general meeting.

- The Company may understand what it is trying to say in a graph or PowerPoint slide, but in order for transparency such that all stakeholders are provided the information that has been deemed the best method in Utah, the Division requests that the Company provided narratives, white papers, or other forms of written explanations of the topics to be covered at stakeholder meetings. This is not any more work for the Company as it has to prepare this information for the written IRP anyway. It is not duplicating efforts and may aid the Company in completing the IRP on time in March.

The next process improvement recommendation that the Division puts forth with respect to IRP meeting management, transparency, and IRP process improvements is a matter that the

Division has previously submitted to the Company on February 13, 2017, in the Company's requested Stakeholder Feedback Form. This document is attached as Attachment C to these comments. In its comments the Division made the following request (this has also been requested in prior IRP cycles):

> Please provide all pdf charts and graphs or other PowerPoint slides that will be presented at IRP stakeholder meetings in their original native format with fully executable formulae intact.

Inasmuch as the Company tends to flip through PowerPoint slides quite rapidly, the Division has asked for the data behind the slides during the IRP process (not at the end), but at each step of the IRP process. Also, inasmuch as the Company has promised to provide this information but has yet to do so, the Division recommends the Commission order the Company to do the following:

- Provide all pdf charts and graphs or other PowerPoint slides that will be presented at upcoming IRP stakeholder meetings in their original *native* format with fully executable formulae intact.

- Provide these at the time when the Company posts the meeting materials that contain the data (which would mean that the Company needs to email or otherwise provide on disc this material one week before the meeting where the topic will be covered).

Finally, the Company has made claims that it is responsive to stakeholder feedback and to parties' comments. Yet, the Division has asked repeatedly, as have other parties, for the Company's responses to each of the respective Stakeholder Feedback Forms that have been submitted and that are posted on the Company's IRP webpage. The Company has ignored our requests, promised us this information would be presented in a PowerPoint slide at the next general meeting, and then finally promised that the responses would be included as an Appendix in the published IRP. None of these promises have been kept. The parties have asked among themselves if the Company had responded to each other's stakeholder feedback, for which each submitting party took the time to fill out the Company's specified form just to get the Company to respond. Discussions among stakeholders revealed that the Company (a) did not ever share its response to feedback forms in writing or on a PowerPoint slide (b) had not even responded to some parties' submitted comments, and/or (c) must not have even read some of our feedback (or at least never responded at least some of the Stakeholder Feedback submissions (see the Division's feedback referenced above).

Therefore, the Division is now sharing with the Commission and other parties Attachment D and Attachment E to these comments, in addition to the previously mentioned Attachments B and C, respectively.

- The Division expressly requests that if a stakeholder has taken the time to complete the Company's own Stakeholder Feedback form and submit it to the IRP mailbox, the Company should at the very next public stakeholder meeting begin the agenda by responding to stakeholders' comments. (This is how CAISO manages its regional integration initiative workshops and appears to be effective). The Commission should at a minimum, direct the Company to respond in writing to the submitting party's comments. Stakeholders have the option of checking the box if they wish to keep their comments private or shared with other stakeholders.

The Division points out that these recommendations are purely process improvements, transparency improvements, recommendations to enable the free flow and sharing of information among stakeholders, and hopefully allow the Company to more efficiently manage its IRP, while taking into consideration the procedural and foundation guidelines authorized by this Commission.

Energy Gateway Transmission Analysis

The Company evaluated four Energy Gateway scenarios for the 2017 IRP:

- Energy Gateway 1: Segment D Windstar to Aeolus 230 kV (one new line and one re-built line) and Aeolus to Bridger/Anticline 500 kV line;
- Energy Gateway 2: Segment F Windstar to Aeolus 230 kV (one new line and one re-built line) and Aeolus to Mona/Clover 500 kV line;
- Energy Gateway 3: Segments D & F Windstar to Aeolus 230 kV (one new line and one re-built line) and Aeolus to Bridger/Anticline, Bridger/Anticline to Populus and Aeolus to Mona/Clover 500 kV lines; and
- Energy Gateway 4: Segment D2 Aeolus to Bridger/Anticline 500 kV line.

The Company's analysis for the 2017 IRP demonstrated that Energy Gateway 4 (Aeolus to Bridger/Anticline) showed potential to align development of this new transmission line with the new PTC-eligible wind resources and provide value for PacifiCorp customers. **The Company refined its analysis during the IRP process, to understand how the most current assumptions would influence potential customer benefits associated with this new transmission line** [emphasis added]. The refined analysis shows that the Energy Gateway 4 scenario, Aeolus to Bridger/Anticline, in conjunction with new wind additions and PTCs, is the most cost-effective Energy Gateway transmission segment, providing the most benefit to customers. Energy Gateway 4 is therefore a component of the 2017 IRP.[44]

The Division has concerns relating to the objectivity of the Company's analysis in determining the best scenario based on the new wind introduced into the portfolio in 2020 when prior IRP cycles showed no need for additional supply-side resources based on future load. The Division questions if this additional wind is driving the need for the new transmission when in

[44] 2017 Integrated Resource Plan, Volume I, Transmission Planning, page 70.

deed the new wind is not needed in the first place but merely modeled for the PTC credits. This question and others are therefore deferred to Docket No. 17-035-40.

The Division understands the Company's responsibility to design its bulk transmission and distribution system to reliably transport electric energy from generation resources (owned generation or market purchases) to and from various load centers. However, the decisions required to accomplish this task have to be prudent and in the public interest.

The Company relies on third party stakeholders[45] to ensure its bulk transmission complies with reliability standards. These third party stakeholders model each segment of the transmission system to identify constraints and the ability to flow power in any direction required. The Company lists several transmission system improvements placed in-service since the 2015 IRP and suggests needed system improvements that will address currently known reliability issues.[46]

Private Generation

Private generation is modeled in the 2017 IRP and past IRP cycles as a reduction to load similar to Demand Side Management (DSM). Unlike Qualifying Facilities, which have to meet certain operating criteria as part of their contract with the Company, the Company has no such operating controls over private generation. As such, private generation is not considered a system resource. The majority of private generation technologies offer low contribution capacities during system peak load times. The Commission affirms that private generation is not a system resource in its November 2015 order for the Net Metering Docket No. 14-035-114.[47]

The Company hired Navigant Consulting, Inc. to update the private generation penetration with new market and incentive developments since the 2015 IRP cycle. The Company asked Navigant to study: (1) technical potential; (2) market potential; and (3) installed cost of energy

[45] Western Electricity Coordinating Council (WECC), Northern Tier Transmission Group (NTTG), Peak Reliability (PEAK), Federal Energy Regulatory Commission (FERC), etc.
[46] 2017 Integrated Resource Plan, Volume I, Transmission Planning, pages 72-74.
[47] Commission Order, Docket No. 14-035-114, In the Matter of the Investigation of the Costs and Benefits of PacifiCorp's Net Metering Program, November 2015, at 13-14.

for each private generation resource in each of the six states served by the Company. The specific technologies studied included solar photovoltaic, small-scale wind, small-scale hydro, and combined heat and power (CHP) for both reciprocating engines and micro-turbines. The IRP models private generation as a reduction to load based on Navigant's research as shown in Table 1 below.[48]

Table 1

Technology	Capacity Factor (kW-DC/kWh-AC)	Capacity Factor (kW-AC/kWh-AC)	Heat Rate (Btu/kWh)
Solar Photovoltaic (AVG)	**15.4%**	**19.2%**	
UT	16.3%	20.4%	
WY	16.8%	21.0%	
WA	14.0%	17.5%	
CA	16.6%	20.8%	
ID	16.0%	20.0%	
OR	12.4%	15.5%	
Small-Scale Wind	**20-25%**		
Small-Scale Hydro	**50%**		
Reciprocating Engine CHP			**12,637**
Micro-Turbine CHP			**15,535**

The Solar Photovoltaic capacity factors as illustrated in Table 1 above are confusing. The Division asked the Company to explain in greater detail why the (kW-AC to kWh-AC) capacity factor is greater than the (kW-DC to kWh-AC) capacity factor. These capacity factor differences denote that in addition to the loss as a result of DC to AC conversion through the inverter, as normally seen with photovoltaic systems, that somehow there can be a greater capacity factor by accounting for the conversion loss normally but correcting for it with a math exercise when using kilo-watt hours after the DC to AC conversion.

The Company's response to the Division's inquiry refers to footnote 16 on page 11 in Appendix O of the 2017 IRP Volume II.[49] Navigant assumes a direct current (DC) to alternating current (AC) de-rate factor of 80 percent.[50] That is, a system with a nameplate capacity of 1,000

[48] 2017 Integrated Resource Plan, Volume II – Appendices, Appendix O – Private Generation, Private Generation Market Penetration Methodology, pages 6-12.
[49] Id., page 11.
[50] This assumes the loss of DC to AC conversion through the inverter, annual degradation and other de-rate factors.

watts DC is assumed to output 800 watts AC. For example, from Table 1 above for Utah, the 20.4 percent kilowatts AC (kW_{AC}) per kilowatt-hours AC (kWh_{AC}) factor is a conversion factor from AC kW output to annual AC kWh generation, by location. In this example, the 800 watts of AC output would be multiplied by 8,760 (hours/year) and then multiplied by 20.4 percent to arrive at annual generation of 1,430 (kWh_{AC}).[51] Another way to understand the capacity factor is to calculate the (kWh_{DC}) and compare it to the annual generation of 1,430 (kWh_{AC}). The 1,000 watts DC used in the example multiplied by 8,760 (hours/year) is 8,760 (kWh_{DC}). The equated (kW_{AC} to kWh_{AC}) of 1,430 (kWh_{AC}) divided by 8,760 (kWh_{DC}) results in a capacity factor (after considering all losses from conversion) of 16.32% which matches the (kW_{DC} to kWh_{AC}) capacity factor in Table 1 for Utah. Having the (kW_{AC} to kWh_{AC}) column in the table seems misleading and unnecessary leading the reader into believing the solar photovoltaic capacity factor is higher than it really is. NREL's System Advisory Model (SAM), when used for specific state locations with proper assumptions, has proven to be a reliable predictor of system performance and is referenced by most stakeholders. Although the Division did not perform its own analysis using NREL's model, Navigant's (kW_{DC}/kWh_{AC}) capacity factors seem to align with capacity factors similar to NREL's model found in other matters.

Capacity factors are good to study as they lead to contribution capacities (how does the resource contribute to the system peak load or coincident Utah load). Private generation is modeled as a reduction to load without any assignment of the incremental costs associated with private generation. The IRP is used to prepare a long-term resource plan that is based on a 20-year planning horizon. To this end, the IRP sensitivity studies capture potential changes to long-term system costs that are increasingly uncertain over the 20-year forecast used for any given IRP. Unlike DSM, private generation supplies energy back to the grid and may have costs that exceed benefits or vice versa to the system. As a result, private generation could change the IRP portfolio at higher penetrations rather than simply reducing load.

As shown in Figure 1 below, Navigant estimates approximately 1.4 GW of cumulative private generation capacity will be installed in PacifiCorp's territory from 2017-2036 in the base

[51] Company response to Division Data Request 3.5.

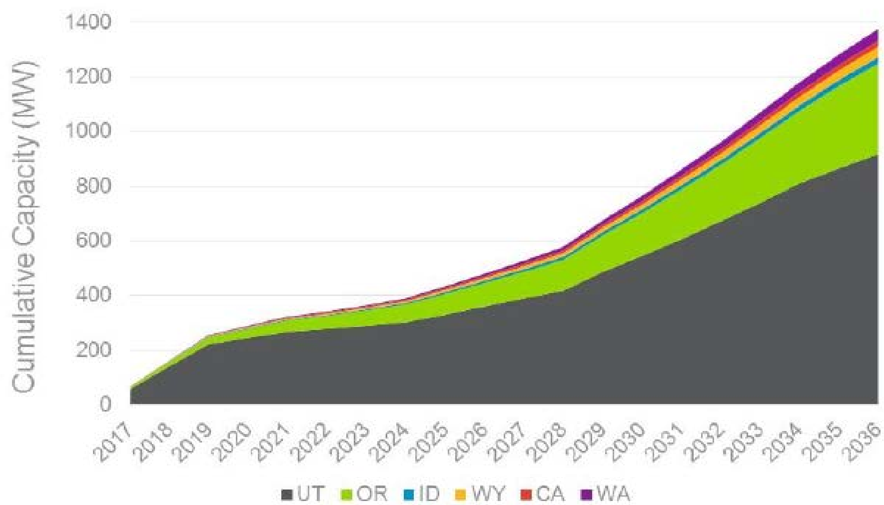
case scenario. The main drivers include variation in technology costs, system performance, and electricity rate assumptions. As in the 2015 IRP, the Navigant study identifies expected levels of customer-sited private generation, which is applied as a reduction to PacifiCorp's forecasted load for IRP modeling purposes.

In response to the Divisions data request 3.4, the Company responds that the Integrated Resource Plan (IRP) is a long-term planning tool that incorporates the best available information at the time to inform its forecasts. If the generation impact of residential solar is greater than the forecast, it could affect IRP resource selections. PacifiCorp conducted both low and high private generation sensitivity studies in the 2017 IRP (PG-1 and PG-2, respectively). Please refer to Volume II, Appendix K, pages 206 and 207 of the 2017 IRP for the portfolios of these sensitivities. Private generation is included as part of the load forecast and will be updated in future IRP cycles. At that time, the most recently available actual sales will be incorporated into the load forecast. These actual sales will reflect the result of realized private generation. The amount of realized private generation will also inform future private generation forecasts that are subsequently incorporated into future load forecasts.

Figure 1[52]

[52] 2017 Integrated Resource Plan, Volume II – Appendices, Appendix O – Private Generation, Executive Summary, Figure 3, page 4.

Figure 3 Cumulative Market Penetration Results by State (MW AC), 2017 – 2036, Base Case



The Division acknowledges the Company's modeling of Private Generation as a reduction to load similar to DSM in the 2017 IRP as explained above. However, private generation affects the system differently than simply a reduction to load.[53] The Division recommends that in future IRP processes, the Company models the costs and benefits of private generation as an intermittent system resource in its supply-side forecasts rather than a reduction to load.

SUMMARY OF RECOMMENDATIONS

The objective of the IRP is used to identify the type and timing of new resources acquisitions that best serve the needs of its utility customers with the least-cost, least-risk standard. This determination is made based on a finding of a capacity or resource need. The Company has no deficiency in meeting its projected future load growth with current resources

[53] For example: California Duck curve impacts to thermal generation ramp rates in the evening, intermittent impacts requiring FOTs, environmental costs and benefits, distribution line losses, etc. The list of costs and benefits are numerous and impact the system differently.

through the IRP planning timeframe.[54] Further, the Company does not need the new wind and transmission resources to meet either state or federal regulatory requirements.[55] However, the 2017 IRP and its Action Plan include wind repowering and new wind and transmission resources that are based on an economic opportunity. Economic opportunities are best evaluated in the context of a rate-based setting, not and IRP setting. The Division recommends the Commission not acknowledge the 2017 IRP or its Action Plan. Further, the Division recommends that the Commission direct the Company toward Utah's IRP objectives, need-based resource planning, and least-cost, least-risk objective as found in the Commission's Standards and Guidelines.

The Division has made several recommendations to the Commission with respect to transparency, process improvements, informational requirements, etc. that if accepted, should improve future year-long integrated planning processes. With respect to content and direction of the IRP, the Division summarizes its findings and recommendations to the Commission below:

The Division recommends the Commission not acknowledge the Company's 2017 IRP or its Action Plan.

- The Division recommends the Commission order the Company to come up with a way to value all future segments of Energy Gateway that takes into account the costs and benefits not modeled in the IRP. The Company must come up with a way other than sensitivities to determine various transmission segments before continuing future Gateway segments and before acknowledgement of transmission projects in an IRP can move forward. (All similar see IRP) The Division requests that the Company hold a separate workshop for all stakeholders to determine if the Company's proposed method is acceptable. Any project that goes through the SBT in future IRPs needs to be subjected to stochastic risk analysis to determine risk and other performance metrics.

- The Division recommends that renewable resources and DG be modeled as separate supply side resource in the 2017 IRP rather than a reduction to load. The Division also recommends that the Commission order the Company to conduct an updated DG

[54] PacifiCorp's 2017 IRP, April 4, 2017, p. 92.
[55] Id. at p. 8.

potential study for the 2017 IRP and present the study findings at an IRP public stakeholder meeting with the authors of the study present.

- The Company should present to the larger stakeholder group all state-specific programs or reports that impact the IRP or that go into IRP assumptions, such as the Energy Trust of Oregon's work that determines DSM potential, or the Northwest Power Pool and Council's work that also influences DSM, etc.

Consider the Risk of Setting Precedent

As previously stated, the Division has serious concerns if these resource actions were to be acknowledged. Utilities would look and find reward for new resource investments in future IRPs that add capital to the rate base but are not needed to provide service. The utility is a regulated monopolist and encourages this. It is conceivable that the future will bring another time-limited opportunity to purchase a natural gas plant or another resource that adds significant capacity and energy to the system, as well as expense to the Company's rate base. If not designed to replace existing coal units or to meet load growth, this supply would not be needed. Yet if found to be economic, the utility could justifiably be acknowledged in an IRP proceeding under an economic opportunity framework.

Each new additional rate-based resource would have the potential to impose new costs to ratepayers, and utilities would see increasing, virtually free returns, counter to the cost of service construct. It is critically important that this IRP not be acknowledged, and that the Commission blocks this chance of setting a harmful precedent. In the instance of a purely economic project, ratepayers should not be expected to bear all of the risk, no more than ratepayers should be expected to bear the risks of utility investment in a merchant power plant.

Conclusion

The Division concludes that the Company's 2017 IRP and Action Plan cannot be found to least-cost, least-risk resources for Utah ratepayers. The Division recommends the

Commission not acknowledge the 2017 IRP. The Division concludes the following based on its analysis of this IRP:

- The identification of a resource need is fundamental to the IRP process.
- The Company's characterization of need in the IRP is not supported by Commission practice.
- Action Items 1a, 1b, and 2a in the Action Plan are inconsistent with need-based IRP planning.
- Action Items 1a, 1b, and 2a in the Action Plan represent economic opportunities and should not be acknowledged.
- The Company's justification for the wind repowering and new wind has not been consistent.
- There are significant customer risks associated with Energy Vision 2020 that do not represent the long-run public interest of Utah ratepayers.

The Division makes several recommendations to the Commission that if accepted will improve the public input process of the Company's IRP.

cc:

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Service List