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State of Utah
DEPARTMENT OF COMMERCE
Office of Consumer Services

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To: Utah Public Service Commission

From: Office of Consumer Services
Michele Beck, Director
Dan Gimble, OCS Staff
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Date: September 7, 2011

Re: In the Matter of the Acknowledgement of PacifiCorp's 2011 Integrated Resource Plan; Docket No. 11-2035-01

I. Background

The Office of Consumer Services (Office) submits these comments to the Utah Public Service Commission (Commission) in the matter of the acknowledgement of PacifiCorp's (PacifiCorp or Company) 2011 Integrated Resource Plan (IRP). The IRP process is designed to evaluate PacifiCorp's forecasted capacity and energy needs, and the costs and risks of different resource options to meet those needs, over a 20-year planning horizon. The primary objective of the IRP is to identify an optimal portfolio of low cost, low risk and reliable resources in order to promote the long run public interest. Other objectives include ensuring that the resource plan: 1) has a sufficient degree of flexibility to adapt to changing conditions (e.g., load growth, gas prices, carbon laws, new technologies, etc.); 2) informs the Company's business plan and 3) is developed using an open public process where key IRP issues are publicly vetted, information is exchanged and input from participants is considered by the Company.

The above objectives (and others) were codified in a set of IRP standards and guidelines, which the Commission published in 1992.[1] For nearly 20 years, these IRP guidelines have been used by parties as the basis for preparing IRP recommendations and by the Commission for deciding whether or not to acknowledge the Company's IRP filings. The Office once again relies on these IRP guidelines in preparing comments on PacifiCorp's 2011 IRP.

[1]PSC Order, June 18, 1992, Docket 90-2035-01.

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II. Acknowledgment

As discussed at greater length in our comments, the Company has not adequately demonstrated that its Re-optimized Case 3 preferred portfolio represents a low cost, low risk and reliable set of resources for Utah residential and small business customers. The Office cannot recommend acknowledgment of this portfolio to the Commission without further analysis conducted by the Company. Such analysis would begin by applying the Company's new "renewable resource policy" criteria to not only the original Case 3 portfolio, but more broadly to the initial 19 core portfolios that were subjected to deterministic and stochastic analysis. Further, the Office questions the veracity of the Company's narrow focus on Wyoming wind as the only viable renewable option. The Company's significant commitment to Wyoming wind appears pre-determined and dependent on the full expansion of the Gateway Transmission Project.

The Commission should direct the Company to uniformly apply its new renewable resource policy criteria to all portfolios evaluated through deterministic and stochastic analysis. This would place all portfolios on equal footing in the process of determining an optimal portfolio for Utah customers. The results from this additional analysis should be filed with the Commission and interested parties. Parties should be provided an opportunity to comment on the updated results prior to the Commission deciding whether to acknowledge PacifiCorp's 2011 IRP.

In addition to the Office's recommendation to not acknowledge the 2011 IRP at this time, we also have recommendations aimed at improving the IRP public process and addressing IRP modeling issues. These specific IRP modeling issues include transmission planning, resource selection, wind integration studies, load forecasts, planning reserve margin, and energy not served.

III. Compliance with IRP Guidelines

The Commission's IRP Guidelines provide direction to the Company and parties in a number of important areas. The Office comments (below) on specific guidelines where it has significant concerns.

<u>Public Process - Guideline 3</u>: "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. PacifiCorp will provide ample opportunity for public input and information exchange during the development of its plan."

The Office is concerned that the Company is moving farther away from the intent of this guideline. While public meetings continue to be held, the Company's focus is on information presentation, rather than public input and information exchange. With regard to the 2011 IRP, the Company failed to timely complete a draft of the IRP so that it could appropriately consider and incorporate comments from parties. The IRP schedule called for a draft to be circulated to parties in early February 2011 with a 30-day comment period. However, a complete draft of the 2011 IRP, which included a number of key chapters, was not provided to parties until March 7, 2011. Incredibly, the public process culminated in a final stage where parties submitted written comments to the Company, which were never considered because the final version of the IRP was already going to print.[2]

The Company clearly failed to meet specifications set forth in this guideline. Parties were afforded little time to review the complete Draft 2011 IRP, which included a large number of sensitivity cases and a major revision to the initial Preferred Portfolio (Case 3) to delay a large gas combined-cycle plant, eliminate geothermal resources and significantly increase wind resources in the plan from 139 MWs to 2,100 MWs. Further, the schedule provided no opportunity for the Company to consider written comments submitted by parties.

If IRP is to serve the long run public interest, then it necessarily must have a credible public process. The Office strongly recommends the Commission take a more "active-directive role" to ensure a credible public process takes place in advance of its formal IRP review process so that parties have "ample opportunity" to provide meaningful input on a draft IRP and comments are taken seriously by the Company.[3]

Optimal Resource Portfolio – Guideline 1: "The [IRP] process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty."

The Office has significant concerns as to whether the Re-optimized Case 3 preferred portfolio selected by the Company represents an optimal set of low cost, low risk resources for Utah customers. This concern relates to the type, timing, cost and reliability of resources included in the Re-optimized Case 3 portfolio. Re-optimized Case 3 is derived from a new set of criteria applied only to the Original Case 3 and this new criteria represents an addition to the standard performance criteria used by the Company to evaluate all candidate portfolios. Table 1 below lists the standard and additional criteria used by the Company.

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[2]Comments on the March 7, 2011 Draft IRP were scheduled to be filed by a number of parties on March 24, 2011. At a meeting on March 23, 2011, Utah parties were informed by the Company that the comments would not be considered prior to the Company filing the 2011 IRP with the state commissions because the IRP documents were scheduled to be printed beginning March 25, 2011. Certain parties, including the Office, still went forward and filed comments to the Company. The Commission has posted copies of party comments on its website.

[3]Procedural Guideline 4 in the 1992 Standards and Guidelines, in part, states: "…The Commission will pursue a more active-directive role if deemed necessary, after formal review of the planning process."

Table 1
Portfolio Evaluation – Standard & Additional Evaluation Criteria

Standard Screening Criteria[4]	Additional Criteria for Re-Optimized Case 3[5]
Risk Adjusted PVRR	Stochastic Deferral Analysis - 2nd Gas CCCT
10-yr Customer Rate Impact	Geothermal Cost Recovery Risk
Cumulative CO_2 Emissions	Public Policy - Clean Energy
Supply Reliability (ENS)	Fuel Price Risk
Resource Diversity	Regulatory Compliance Risk
Future Uncertainty - GHG & RPS policies	

The application of additional criteria to the original Case 3 portfolio results in the Company developing a Re-optimized Case 3 portfolio that includes a one-year deferral of a large gas plant, the elimination of 220 MWs of geothermal resources and a substantial increase in wind resources from 139 to 2,100 MW over the next 20 years.

It is important to note that the Company did not apply the additional criteria in evaluating any of the other core portfolios. The Company also did not compare the Re-optimized Case 3 with the original eight cases that were short-listed in the final screening process.[6] Therefore, the Office requested such a comparison (in OCS DR 2.2) using the standard screening criteria (i.e., Risk-Adjusted PVRR, 10-year customer rate impact, etc.). Table 2 below shows the rankings for the Original and Re-optimized Case 3 portfolios based on the CO_2 average scenario.[7]

Table 2
Original & Re-optimized Case 3 Rankings

Standard Screening Criteria	Original Case 3 Ranking	Re-Optimized Case 3 Ranking
Risk Adjusted PVRR	1	7
10-yr Customer Rate Impact	1	9
Cumulative CO_2 Emissions	7	2
Supply Reliability (ENS)	6	7
Resource Diversity	Tied for 7	1

The results generally show a sharp difference between the Original and Re-Optimized Case 3 portfolios. Where the Original Case 3 is strong; the Re-Optimized Case is weak (and vice versa). Of particular concern is that the Re-optimized Case 3 ranks low to very low (7 – 9) in the important areas of Risk-Adjusted PVRR, 10-year customer rate impact and supply reliability. As to projected rate impacts on customers, there is about a 6.5%

[4] 2011 IRP; pg. 153 and pg. 217 – 219
[5] 2011 IRP; pg. 228
[6] The cases subjected to final screening included Cases 1, 3, 4, 5, 6, 7, 9 and 15.
[7] The results are not materially different for other CO2 cost scenarios (None, Medium, Low to High).

higher rate impact over 20 years for the Re-optimized Case 3 compared to the Original Case 3. Given the high costs and low reliability attributes of the Re-Optimized Case 3, it is puzzling why the Company has selected this particular case as the new preferred portfolio.

Lastly, the Office notes that the Re-optimized Case 3 is closely aligned with the Case 19 Business Plan for the first ten years of the planning horizon. The primary difference is that Case 19 has more Class 2 DSM resources (+220 MW) and less renewables (-222 MW) than the Re-optimized Case 3.[8] Table 3 below compares the resource amounts for Case 19 and Re-optimized Case 3.

Table 3
Case 19 and Re-optimized Case 3 - Resource Levels (MWs)

10 Year Resource Additions (MW)	Case 19 – Business Plan	Re-optimized Case 3	Difference
Gas Plants	1,819	1,697	(122)
Coal Plant Upgrades	63	63	0
Geothermal	0	0	0
Wind	660	800	140
CHP/Biomass	0	52	52
DSM, Class 1	157	250	93
DSM, Class 2	1,409	1,189	(220)
Micro/Oregon Solar	19	49	30
FOTs	921	961	40

Case 19 performed poorly in the initial stochastic screening results and was not even included by the Company on its short list of cases subjected to further evaluation.[9] The additional criteria used to develop the Re-optimized Case 3 appears to be a backdoor attempt to align the IRP outcome with the Business Plan, despite the fact that the business plan case failed to pass muster in the initial stochastic analysis.

Consistency in Comparing Resources – Guideline 4(b): "An evaluation of all present and future resources, including future market opportunities (both demand-side and supply-side), on a consistent and comparable basis."

The Office has two specific concerns about resources that are not being evaluated on a consistent and comparable basis: the unjustified elimination of geothermal resources from consideration and the lack of inclusion of substantial capital investments in pollution control technologies at the Company's existing coal plants. The Company's approach introduces a bias against geothermal and a bias in favor of coal plants. The Office's concerns are discussed in greater detail in Section V, B. Resource Selection.

[8]The 222 MW of additional renewable resources in the Re-optimized Case 3 consists of 140 MW of Wind, 52 MW of Biomass and 30 MW of Micro/Oregon Solar.
[9]See the scatter-plot diagrams in the section of the 2011 IRP entitled "Initial Screening Results," pg. 213 – 216. These diagrams show that Case 19 was not a top-performing portfolio based on a combination of stochastic mean PVRR and upper-tail PVRR.

IV. Derivation of Revised Preferred Portfolio

As indicated above, the Office is concerned that the Re-Optimized Case 3 preferred portfolio, and the process leading to its development, is not in the public interest. This section provides a description of that process and outlines our concerns.

Initial Case 3

The results from the deterministic and stochastic analyses[10] led the Company to initially select Case 3 as its preferred portfolio of resources. However, Case 3 included only 139 MWs of wind resources over a 20-year planning horizon, which is significantly lower than other portfolios evaluated. To put the 139 MW in perspective, the Company has acquired more than this amount of wind in every single year since 2007. The Company also expressed concerns about the regulatory risk of recovering development costs associated with geothermal resources identified in Case 3 and acquiring two large CCCT plants in sequential years.

Re-optimized Case 3

The foregoing concerns prompted the Company to modify Case 3 in three ways:

- Defer the second 597 MW gas CCCT from 2015 to 2016. Third quarter Front Office Transactions (FOT) were increased by 597 MWs in 2015 to fill the resource gap.
- Replace geothermal resources with 1,300 MW of “geothermal–equivalent” wind capacity.[11] The Company then increases wind by an additional 800 MWs to attain a prescribed policy level of 2,100 MWs.[12]
- Revise renewable resource policy assumptions to be consistent with Waxman-Markey RPS targets and extend the renewable production tax credit (PTC) from 2015 to 2020. System Optimizer runs were performed based on these renewable policy assumptions to 1) lend support to the 2,100 MW policy target for wind resources and 2) allocate the wind capacity across a time period of 2018- 2029. The level of wind acquired through these deterministic runs is 1,029 MWs over the 20-year planning horizon, which is only about 50% of the 2,100 MW policy target established by the Company.

[10]Chapter 7 of the 2011 IRP discusses PacifiCorp’s modeling approach and includes descriptions of the deterministic (optimization) analysis using the System Optimizer model and the stochastic (risk) analysis using the PaR model operated in stochastic mode.

[11]The Company defined this “equivalency” based on a calculation for substituting wind resources for geothermal resources using the ratio of respective capacity factors for geothermal (90%) and Wyoming wind (35%).

[12]The process used by the Company to dramatically increase wind to a policy target of 2,100 MW is based on stochastic upper-tail mean PVRR performance of all 19 core portfolios. From these 19 portfolios, the Company takes the average capacity from the three top-performing portfolios to derive approximately 750 MWs of “wind” and and 1,300 MWs of “geothermal-equivalent wind.” This manipulation is used to support a 2,100 MW wind renewable policy target for the period 2018 - 2029.

Together, the two modifications involving wind resources led the Company to sharply increase the amount of targeted wind capacity to 2,100 MWs. All new wind resources are assumed to be located in Wyoming and are accessed via the expansion of the Gateway Transmission System. The Company manually set the annual acquisition levels for Wyoming wind, as indicated in Table 4 below.

Table 4
Scheduled Wind Additions

Year	MW
2018	300
2019	300
2020	200
2021	200
2022	200
2023	200
2024	200
2025	100
2026	100
2027	100
2028	100
2029	100

The Office has a number of comments on the Re-Optimized Case 3 portfolio:

- Deferral of the second 597 MW CCCT by one year produces a very small benefit to customers of $23.6 million, as measured by a reduction in the stochastic mean PVRR. However, there is slight increase in risk as measured by the upper tail mean PVRR.

- The Original Case 3 portfolio included 220 MWs of geothermal resources. The Re-optimized Case 3 inflates geothermal resources to 500 MWs and then replaces geothermal with 1,300 MWs of "geothermal-equivalent" wind resources based on an *ad hoc* approach developed by the Company to target "risk-mitigating" renewables.[13] Thus, the Company essentially replaces 500 MWs of geothermal resources with 1,300 MWs of wind resources without analytical justification.

- The replacement of 500 MW of geothermal resources by 1,300 MWs of Wyoming wind resources in the Re-optimized Case 3 appears necessary to support a full expansion of the Gateway Transmission Project. Without a high commitment to wind acquisition in Wyoming, a full Gateway transmission expansion may not be justified. The Company acknowledges this concern on pages 81-82 of the 2011 IRP:

[13]See the 2011 IRP, Table 8.13, on pg. 226 (and the accompanying narrative).

> "Unless significant wind resources are added to Wyoming as in the high CO_2 and high natural gas cost scenarios, the utilization percentage of Gateway West and Gateway South would be fairly minimal. This would be a prime factor for the Company to decide not to pursue building these incremental transmission segments."

- The Company performed deterministic runs to recast the initial Case 3 to a "greener" portfolio based on the more liberal renewable policy assumptions of Waxman-Markey RPS levels and an extension of the renewable PTC to 2020. The results from these deterministic runs indicate that the System Optimizer model adds a total of 1,029 MWs of wind over the 20-year planning horizon. Of the 1,029 MW total, the model selects 547 MWs of wind capacity in Washington, Idaho and Utah over a relatively narrow window of time (2015 – 2017).[14]

  This analysis leads to some rather interesting observations. First, the Company's deterministic analysis only supports the addition of 1,029 MWs of wind over the planning horizon; an amount that is only about 50% of the targeted 2,100 MWs of wind in the Re-optimized Case 3 portfolio. Second, the System Optimizer model selects 547 MWs of wind resources in states other than Wyoming and advances the addition of those wind resources to 2015-2017.[15] This raises important issues as to what is the total amount of wind that can be economically justified, when should it be developed and where should it be located.

- The "Waxman-Markey RPS" and "PTC extension to 2020" renewable policy assumptions were only applied by the Company to "re-optimize" the initial Case 3 to a portfolio that included considerably more wind resources. These new renewable policy assumptions were not broadly applied to the initial set of 19 core portfolios. Had these renewable policy assumptions been more uniformly applied, a different preferred portfolio may have emerged from a full analysis of candidate portfolios. The Commission should direct the Company to uniformly apply the new renewable policy assumptions to all 19 core portfolios and file the results with the Commission and interested parties.

[14]See 2011 IRP, Table 8.14 – Wind Additions under Alternative Policy Assumptions, pg. 227.

[15]In response to OCS 2.5, the Company provides the results of a scenario requested by the Office that would replace 500 MW of Wyoming wind with 500 MW of wind resources sited in Washington, Idaho and Utah. The acquisition of wind from these three states occurs in 2015 – 2017, which is consistent with the wind levels from the deterministic model runs shown in Table 8.14 (pg. 227) of the 2011 IRP. The "Advance Wind" scenario results show an increase in the stochastic mean of $153 million compared to the Re-optimized Case 3. However, the Company does not indicate whether an "Advance Wind" scenario improves upper-tail risk. Nor do they indicate whether costs associated with the full expansion of the Gateway Transmission System were reduced in this scenario where less wind resources are acquired in Wyoming. There also may be diversity benefits associated with locating wind resources in different states that were not captured in the stochastic modeling.

- The 2011 IRP fails to address the potential economic consequences of delaying the addition of new wind resources until 2018. Specifically, the Company may miss opportunities to develop or acquire incremental wind generation at superior wind locations in terms of wind performance characteristics and proximity to transmission. In response to OCS DR 3.2, the Company indicates that it holds development rights at the McFadden Ridge, Dunlap, Wild Horse and 12-Mile properties. These wind development sites total approximately 800 MWs; an amount considerably lower than the targeted 2,100 MWs of wind resources in the Re-optimized Case 3.

- The Company's schedule set forth in Table 4 above calls for the acquisition of 200-300 MWs of wind resources in 2018 – 2024. However, the Company stated in the 2008 IRP that it was difficult to acquire a significant amount of wind resources in a single year and proposed to "smooth out" additions to mainly 100-200 MW annual increments from 2012 through 2018.[16] The Company provides no explanation why it now believes that it is possible to acquire and integrate a higher annual amount of wind resources into its system.

V. Modeling Issues

The 2011 IRP includes a number of key modeling issues. In this section, the Office provides its comments on the specific issues of transmission planning, resource selection, load forecasts, wind integration costs, planning reserve margin and energy not served.

A. Transmission Planning

The Energy Gateway Transmission Project (in particular the Gateway West and Gateway South segments) appears to overly influence the final resource selection in the revised preferred portfolio. Although these transmission segments are not yet built, the Re-optimized Case 3 portfolio is critically dependent on the full Gateway configuration.[17] The justification for the selection of the revised preferred portfolio and the completion of the full Energy Gateway appears to be based upon circular logic. Wind resources located in Wyoming cannot be added economically without the full Gateway and the full Gateway build out is not economical unless it is needed to access Wyoming wind as required by potential and uncertain increases in RPS standards, carbon taxes and fuel prices.

By hardwiring the full Energy Gateway project and more expansive renewable requirements into the final IRP modeling process, the Company essentially has predetermined a resource future, i.e., wind in Wyoming. The Company's revised preferred portfolio locks into Wyoming wind over the 2018 to 2029 time period (see Table 4 above) which in turn locks into the requirement for the completion of the Gateway West and South projects in approximately 2018-2019. By doing this, the Company foregoes

[16] PacifiCorp 2008 IRP, Table 9, pg. 254
[17] Response to OCS Data Request 2.4

the opportunity to build other transmission projects which could support other technologies such as geothermal, utility scale solar or storage located in other regions of the West.

The Company's current transmission system (without the remaining Gateway segments) is able to support the current known renewable requirements. The original Case 3 preferred portfolio meets current state RPS yet only includes an additional 139 MW of wind along with 220 MW of geothermal. Additional transmission scenarios performed under the Incumbent Resource Future[18] also meet current state RPS standards and include only up to an additional 100 MW of wind resources. Significant amounts of wind resources are acquired under only the high CO_2/high gas scenario. The 2,100 MW of wind targeted in the revised preferred portfolio is not a mandatory resource requirement. It appears it is only required in order to support the full Gateway expansion. At the completion of the Incumbent Resource Future analysis the Company states:

> "Unless significant wind resources are added to Wyoming as in the high CO_2 and high natural gas cost scenarios, the utilization percentage of Gateway West and Gateway South would be fairly minimal. This would be a prime factor for the Company to decide not to pursue building these incremental transmission segments."[19]

To provide justification for the Gateway projects, the Company conducted analysis of four Gateway scenarios ranging from "limited" to "full." In this analysis, the Company generates Present Value of Revenue Requirement (PVRR) numbers for the full Gateway project that are superior to all other Gateway scenarios in both the Green Resource Future and the Incumbent Resource Future strategies.[20] The Office submitted data requests to determine the specific factors that swung the PVRRs in favor of a full Gateway expansion, which is $4.1 billion higher than limited Gateway in terms of gross capital costs.[21] The determining factors appear to be 1) an assumption of more costly wind in Idaho, Utah and Washington and the associated new west-side transmission lines, 2) transmission constraints in the Yakima and Goshen bubbles that increase un-served energy and DSM costs, and 3) the reduction in the allocation of capital costs in the full Gateway scenario due to higher capacity path ratings of the transmission lines.[22] Due to the complexity of the modeling, it is difficult to determine if the financial analysis supporting a full Gateway scenario is reasonable.

Rather than simply defend the building of a very expensive transmission project, the Office believes the IRP modeling should demonstrate how robust and flexible the

[18]Two strategies were developed to perform additional transmission analyses – Green Resource and Incumbent Resource Futures. The Incumbent Resource Future assumes current state RPS/Bingaman renewable standards while the Green Resource Future assumes higher Waxman-Markey renewable standards and higher CO_2 taxes.
[19] PacifiCorp 2011 IRP Volume I, March 31, 2011, pgs 81-82.
[20] PacifiCorp 2011 IRP, Tables 4.2 and 4.4, pgs 78 and 81.
[21] PacifiCorp 2011 IRP, Volume II, Tables C.1 and C.2 pgs 50 and 51.
[22] Responses to OCS Data Request Sets 4 and 5.

Gateway transmission plan is over various resource scenarios. Instead, the Company justifies a transmission plan and a resource portfolio by focusing on their pre-determined interdependencies.[23]

B. Resource Selection

<u>Geothermal Resources</u>

The Company eliminates geothermal resources from consideration until such time as regulatory recovery of well development costs is assured. The Company's special treatment of geothermal resources, as compared to the evaluation of other resources, deviates from IRP Guideline 4(b). There are risks and uncertainties attendant to the development of all resources; geothermal is no exception. The Office notes that while PacifiCorp is reluctant to build or acquire geothermal resources, an MEHC subsidiary, CalEnergy, is developing 470 MWs of geothermal capacity in California's Imperial Valley.[24] PacifiCorp's reluctance appears to stem more from the Company's Gateway Transmission Project – Wyoming wind strategy than a concern about possible non-recovery of geothermal well development costs.

According to the recent Black and Veatch study commissioned by PacifiCorp in response to the Commission's last IRP Order, an 81 MW expansion at the proven Blundell site is estimated to cost between $46-$51/MWh. Thus, the Blundell expansion appears to be a very cost-effective resource when compared to resource alternatives.

In its Action Plan the Company should explicitly state the regulatory steps that it believes are necessary to be in a position to target a staged acquisition of an 81 MW geothermal resource at the Blundell site by 2015.[25] While parties may have different views on assurances relating to recovery of well development costs, the Company needs to make a specific proposal in order to move the discussion forward.

<u>Existing Coal Resources and Pollution Control Technologies</u>

Coal-fired generation currently comprises 47.5% of PacifiCorp's total resource capacity. These coal plants are supplied from a mix of cost-of-service mines and market coal sources. The Office retained an outside consulting firm, Energy Ventures Analysis (EVA), to perform a comprehensive audit of the Company's coal supply strategy for its coal fleet.

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[23]The Office notes that given these interdependencies between hand-chosen resources and the Gateway project, this analysis should not be seen as sufficient to justify need for the next segments of the Gateway project.

[24]Testimony of Catherine Wollums, on behalf of MEHC, before the Committee on Environment and Public Works, U.S. Senate, June 15, 2011.

[25]In response to OCS 2.8, the Company discusses steps that it intends to take over the next year related to potential expansion at the Blundell site. These steps include: 1) update the reservoir model of the existing geothermal resource to determine a reservoir management plan that could be used for further expansion; and 2) finalize permitting and engineering of production/injection wells that were drilled in 2008 to Blundell Units 1 and 2. This integrated well field is required to support any expansion at the Blundell site. These necessary technical "staging" steps, as distinct from regulatory steps, are generally referred to under Action Item 1, "Geothermal" bullet, 2011 IRP, Volume I, pg. 254.

The audit results indicate that the Company currently faces significant supply and cost issues at various coal-fired generation stations. Issues include coal availability, changes in coal quality and potential cost increases in the areas of coal supply and transportation. EVA produced a Coal Report that documents its audit results and recommendations.[26]

In PacifiCorp's Utah 2011 General Rate Case, the Company filed for cost recovery of pollution control technology (PCT) upgrades associated with nine coal units. An economic analysis of these PCT upgrades occurred outside the IRP process. Witnesses for a number of parties recommended the IRP as the proper forum for future evaluation of PCTs and resource alternatives.

At the July 12, 2011, IRP modeling tutorial, the Office asked whether PCTs could be reflected in the Company's IRP models as options. Apparently, the PCTs could be modeled as "betterment" options. However, the Office is unclear as to the specific modifications that would be necessary and to what degree this change would affect modeling complexity and reliability of results.

The Office recommends that the Commission order the Company to begin to incorporate a more refined analysis of coal-related issues in modeling coal plant displacement scenarios in future IRPs. At a minimum, the Company must reflect updated conditions regarding increasing costs associated with coal supply sources, availability and quality. Further, to develop portfolios and action plans that are in the public interest, no additional significant investment in PCTs should be pursued without a more robust economic analysis of the long-term costs of replacement options.

<u>Demand Side Management Resources</u>

In the Re-optimized Case 3 preferred portfolio, 2,534 MW of Class 2 DSM (energy efficiency) is added over the 20-year planning horizon. This represents the largest single resource added in the preferred portfolio. The Company states that greater reliance on energy efficiency relative to the 2008 IRP is due to larger forecasted potential, the application of new or updated cost credits and the switch to the Utility Cost Test for evaluating Utah DSM resources.[27] The new cost credits applied to Class 2 DSM resources are $54/kw-year for transmission and distribution investment deferral and $14.98/MWh for stochastic risk reduction.

The Company bases its DSM resource estimates on the 2010 DSM potential study, conducted by The Cadmus Group. The Cadmus report states that there are 1,156 aMW of achievable technical class 2 DSM electrical energy savings over the 20-year planning horizon (2011 to 2030) in the PacifiCorp service territory (excluding Oregon). Of these savings, 64% are retrofit opportunities while 36% are for new construction or replacement

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[26]The EVA Coal Report is, in part, based on confidential information that PacifiCorp classified as confidential and to which access was restricted beyond the standard protective order. The Office will file a motion for a protective order that will properly limit the disclosure of confidential information to the Commission and the Division of Public Utilities.

[27] PacifiCorp 2011 IRP, Volume I, pg. 208

of equipment at the end of its normal life cycle. In terms of sectors, 44% of these savings are achievable in the residential sector, 31% commercial, 23% Industrial and the remaining in irrigation and street lighting.[28] Cadmus also states that the cumulative achievable technical potential of Class 2 DSM for peak demand reduction is 2,650 MW in 2030 (page ES-3). The 2,534 MW of Class 2 DSM included in the Company's preferred portfolio is 97% of the achievable potential identified by Cadmus. The Office questions whether such a high percentage of potential DSM resources can be economically acquired.

The 2011 IRP Action Plan calls for the Company to acquire up to 1,200 MW of cost-effective Class 2 programs by 2020. This represents an annual average resource addition of 119 MW between 2011- 2020. The Action Plan also states that programs will be procured through the currently active DSM RFP and subsequent DSM RFPs. Table 5 below compares the Class 2 DSM annual target levels in the 2011 IRP with the 2008 IRP and 2008 IRP Update.

Table 5
Class 2 DSM (MW) in Resource Plan

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
2008 IRP	88	91	93	94	95	95	97	88	87	88
2008 Update	105	105	108	108	86	87	78	77	80	81
2011 IRP	108	114	111	118	122	124	126	120	122	125
2011 IRP vs. 2008 U	3	9	3	10	36	37	48	43	42	44

According to the 2010 Utah annual DSM report, Rocky Mountain Power achieved 36.5 MWs of savings from DSM energy efficiency acquisitions in Utah.[29] Assuming a similar level of success in acquiring Class DSM 2 resources across all PacifiCorp service territories, the Company may have optimistically achieved approximately 90 MWs in total for 2010. The preferred portfolio targets 108 MWs of Class 2 DSM in 2011 or 20% more than the estimated amount achieved in 2010. The Office notes that the most current DSM RFP from 2008 has not resulted in significant new DSM resources. With this in mind, the Office questions whether a level of 108 MW is achievable in 2011 and if the higher targets are obtainable in later years.

[28] Page ES-6, Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources, Volume I, The Cadmus Group, Inc, March 31, 2011.
[29] Rocky Mountain Power, 2010 Annual Energy Efficiency and Peak Reduction Report – Utah, Table 1, page 5.

According to the Cadmus Report, achieving the larger forecasted Class 2 DSM potential may require increasing participant incentives above the current level of 50% of measure costs. Cadmus further states: "…although higher incentives do not affect the total resource costs, they do increase the cost burden borne by the utility and its customers, leading to higher rate impacts with sometimes concomitant customer equity ramifications."[30] Therefore, the Office is concerned that an increasing cost burden may fall on shoulders of ratepayers and equity issues may become more prevalent in the future.

While the Office commends the Company for its assertive program targeting Class 2 DSM additions, we do have concerns as to whether these targets are achievable, economical and fair to customers. The Office has the following recommendations related to Class 2 DSM:

(1) There should be a stronger tie between Class 2 DSM resource procurement planning and the IRP. The IRP should provide more detail on how the Company intends to acquire Class 2 DSM resources at these higher levels.
(2) The Company should provide an analysis of program incentives including the cost and equity impacts on customers.

<u>Market Reliance</u>
Market reliance reflects the amount of short-term market resources or "Front Office Transactions" (FOTs) the Company relies on to meet annual load requirements. PacifiCorp has relied heavily on FOTs in recent IRPs to meet forecasted load requirements; particularly load growth in the early years of the planning horizon. Table 6 below compares the Company's total level of FOTs in the 2008 IRP, 2008 IRP Update and 2011 IRP, for the time period of 2011 - 2020.[31]

Table 6
MWs of FOTs in Resource Plan

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
2008 IRP	209	1,233	1,332	939	941	917	1,006	1,382	1,521	1,583
2008 Update	0	604	932	1,223	794	922	958	636	794	983
2011 IRP	350	1,239	1,429	1,190	1,149	775	822	967	695	995
2011 IRP vs. 2008 U	350	635	497	-33	355	-147	-136	331	-99	12

[30] Cadmus Report, Pg. ES-7
[31] After 2020, growth resources at specific locations are used instead of FOTs associated with western market hubs.

As shown in the last row of Table 6, the Company projected near-term reliance on Front Office Transactions (FOT) in the 2011 IRP is higher than in the 2008 IRP Update. Projected FOT levels are generally lower after 2015, except for 2018. Management decisions to defer the Lake Side 2 CCCT resource from 2012 to 2014 and the next large (547 MW) gas CCCT resource from 2015 to 2016 explain a significant amount of the near-term increase in market reliance in the 2011 IRP.

Justification for these decisions, in part, is provided in the Company's analysis of the WECC's 2010 Power Supply Assessment (PSA), which is found in Appendix H, Western Resource Adequacy Evaluation. WECC's 2010 PSA indicates that all sub-regions (Basin, Desert Southwest, etc.) are expected to remain surplus until approximately 2018.[32] The significant change from the results of the 2009 PSA[33] appears to chiefly result from WECC's use of the Promod IV production cost model, which allows for a more sophisticated modeling of sub-regional reserve margins.[34] Based on this information the Company concludes that adequate market liquidity and depth exists to "maintain positive target reserve margins for several years."

The results of WECC's 2010 PSA alleviate some of the pressure to bring new resources on-line quickly.[35] However, the Office continues to believe it is important that the Company maintain appropriate levels of market reliance, as justified by a reasonable assessment of market depth and liquidity, and continue to monitor this issue.

C. Load Forecasts and Modeling

Change in Stochastic Load Parameters

In this IRP the Company makes a fundamental change to its modeling assumption by setting the long-term load volatility parameters to zero. According to the Company, this change is necessary because the PaR model cannot re-optimize resource additions to met variations in long-term loads. The Company also claims that allowing these load parameters to vary increases the severity of un-served loads and may bias comparisons among portfolios. The PaR model vendor, Ventyx, apparently supports this modeling change.

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[32]The Basin sub-region, which includes Utah, N. Nevada and Idaho, is the first sub-region to report a deficit and does so in 2018.

[33]The 2009 PSA forecast showed most sub-regions going deficit much earlier than the current 2010 PSA. For example, the Basin sub-region was deficit as early as summer 2013 in the 2009 PSA.

[34]The new model relies on coincident peak demand forecasts and allows for better optimization of power transfers among WECC sub-regions.

[35]The Office notes the Desert Southwest's large, positive reserve margin appears to diminish more quickly than other sub-regions such that it is closer to achieving load-resource balance in the 2016-2017 timeframe. Since PacifiCorp is an active buyer and seller of power in the Desert Southwest, this could have important repercussions after 2016.

There was little discussion of the implications of this decision in public meetings. More importantly, the Company did not perform any scenario analysis that tested the impact of setting the long run load volatility parameters at different levels. Thus, the Company has not justified whether this change enhances or diminishes the robustness of its risk analysis.

The Commission should order the Company to either fully support its proposed change or revert back to its prior approach of allowing long-term loads to vary in the stochastic analysis. The Office also recommends that Ventyx provide a technical paper explaining why it endorses this modeling change, the implications of this change for risk analysis and whether this change has been recommended to and adopted by other clients.

Load Forecasts

The Office hired a consultant, GDS Associates, to review the Company's load forecasting models and peak and energy load forecasts in connection with PacifiCorp's 2008 IRP (09-2035-01). GDS prepared a Load Forecast Report that included it analysis, conclusions and recommendations. This Report was attached to the Office's comments on the 2008 IRP. In its 2008 IRP Order, the Commission directed the Company to comply with two of GDS's recommendations (i.e., produce a stand-alone forecast; develop a range of forecasts) and consider changes based on other GDS recommendations.

GDS Associates was once again retained by the Office to review the reasonableness of the Company's load forecasting models and load forecasts in connection with the 2011 IRP. The Office also asked GDS to investigate several new and outstanding issues in the area of loads and load forecasts. The GDS 2011 Load Forecast Report is included as Attachment 1 to the Office's IRP comments.

The recommendations contained in the GDS 2011 Report are summarized below:

1. Instead of relying on one economic forecast (IHS Global Insights), the Company should obtain multiple forecasts in order to compare forecasts and to determine whether one particular forecast or a blend of forecasts is preferable for IRP purposes.
2. Instead of using employment as the driver for commercial and industrial sales, the Company should use some measure of commercial and industrial output such as retail sales or gross regional product.
3. Line loss projections for Utah and Oregon should be investigated for possible modifications.
4. The Company should review economic range forecasts prepared by other utilities and begin to produce range forecast that reflect greater uncertainty in later years of the forecast horizon.
5. The Company should move from a 1-in-10 year weather scenario to a 1-in-20 year weather scenario to produce a more extreme weather case.

D. Other Modeling Issues

PacifiCorp's 2010 Wind Integration Study

In Docket 10-035-124, Office witness Falkenberg prepared a Technical Appendix (Exhibit OCS 4.3) that contains a critique of PacifiCorp's 2010 Wind Integration Study. Mr. Falkenberg's critique identifies numerous modeling flaws in the Study and provides recommendations to remedy these problems for test year purposes in the rate case. One of his general recommendations, which has both ratemaking and planning implications, is that the Company should organize a Technical Review Committee to objectively direct and review work pertaining to the Company's future wind integration studies. The Office has attached Exhibit OCS 4.3 as Attachment 2 to its IRP comments for reference purposes.

Given that wind is a prominent resource in the Company's Re-optimized Case 3 preferred portfolio, the Office recommends the following:

(1) An updated Wind Integration Study should be prepared in conjunction with the 2013 IRP filing.
(2) The concerns raised by Mr. Falkenberg in his critique should be fully examined as part of the Study.
(3) A Technical Review Committee should be organized to direct and evaluate work related to that Study.
(4) Expertise from Utah parties should be represented on the Technical Review Committee.

Planning Reserve Margin

In comments on previous IRPs, certain parties (including the Office) questioned the Company's use of a relatively low planning reserve margin (PRM) of 12.0%. The Office and other parties recommended that the Company conduct a rigorous Loss of Load Probability (LOLP) study to aid in the determination of an appropriate capacity PRM for planning purposes. In response, the Company performed a stochastic LOLP study to identify a PRM target for the 2011 IRP.[36]

The 2011 LOLP study results indicate a PRM target of 14.8%; a level that is close to the 15.0% PRM recommended by the Office and other parties in past IRPs. However, the Company adjusts down the 14.8% result to a recommended 13.0% PRM based on a proxy 1.5% reduction used by the Rocky Mountain Reserve Group to account for a reserve sharing program. The Company justifies this adjustment by referencing a similar reserve sharing program in the Northwest Power Pool; a program that provides one-hour assistance to a utility that loses a generating resource or transmission path. However, the Company did not provide analysis supporting the 1.5% reserve sharing adjustment and indicated that it plans to further test the reasonableness of this adjustment in the next IRP.

[36]The new LOLP Study is in Appendix J to the 2011 IRP. The Office notes that this represents the first new LOLP Study since 2004.

The Office is pleased that the Company updated its LOLP study for purposes of selecting a PRM. The study results indicate that the Company should plan to a higher, 14.8% PRM compared to the 12.0% relied on in past IRPs. Regarding the Company's selection of a 13.0% PRM for the 2011 IRP, the Office offers the following comments:

(1) Some level of adjustment to account for reserve sharing associated with the Northwest Power Pool appears to be analytically supportable. However, the Company only provides indirect evidence to support a 1.5% downward adjustment to the 14.8% PRM resulting from the LOLP study.
(2) If the Company had rounded up instead of down from the adjusted PRM of 13.3%, it could have just as easily selected 13.5% instead of 13.0% as its target PRM.[37]
(3) The LOLP study was based on a one-year snapshot of loads and resources. That year was 2014 - a year when a large gas CCCT plant is added to meet loads and enhance reliability. If the Company had selected a different year for the study, then a higher target level of PRM may have resulted.

In the 2011 IRP Update, the Company should provide an analysis, based on the Northwest Power Pool program, to support a reserve sharing adjustment that more directly relates to its western and eastern control areas. For purposes of the current 2011 IRP, the Office submits that a more conservative PRM ranging between 13.5% - 14.0% represents a reasonable PRM level.

<u>Energy Not Served</u>
Energy Not Served (ENS) is a stochastic measure of the supply reliability associated with different portfolios. ENS "events" typically result from large random load shocks combined with unplanned unit outages in the stochastic modeling. The analysis involves determining the annual mean ENS and upper tail mean ENS for candidate portfolios. In the final screening results of eight candidate portfolios, the original Case 3 preferred portfolio finished sixth in both categories. The Re-optimized Case 3 preferred portfolio fared no better, ranking close to last in both categories.[38] Thus, ENS concerns exist with either of the Case 3 portfolios.

Regarding the projected cost impact on ratepayers resulting from ENS, the Company continues to use a tiered pricing approach[39] instead of a more traditional approach of using the $750 FERC price cap as a proxy for valuing the cost of emergency power. As

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[37]The Company does not fully explain why it rounded the 13.3% down to 13.0% instead of up to 13.5% (see 2011 IRP, Appendix J, pg. 255).
[38]The Re-optimized Case 3 ranked 8th in mean annual ENS and 7th in upper-tail mean ENS, respectively. (Response to OCS 2.2, Table 8.6)
[39]The tiered prices (real dollars) are the same as in the 2008 IRP and are as follows: $400/MWH for first 50 GWh/yr of ENS; $200 for the next 100 GWH/yr.; and $100/MWh for all quantities above 150 GWh/yr. The Company's "theory" underlying the modeling of ENS is that if large quantities of ENS are forecasted in out years, then the Company would likely acquire peakers and $100/MWh reflects the all-in cost for peaking generation. (See 2011 IRP, pg. 199)

indicated on page 249 of the 2011 IRP, the use of the standard FERC price cap approach raises ENS cost by $158 million over the 20-year simulation.

The Company's tiered pricing approach to ENS continues to understate the possible impact on customers of not having adequate resources to meet loads. Thus, the Office recommends that the Commission direct the Company to use the more traditional FERC price cap approach for valuing the impact of ENS when comparing portfolios in the stochastic analysis.

VI. Conclusion and Recommendations

As discussed in the Acknowledgment Section at the beginning of these comments, the Company has not adequately demonstrated that its Re-optimized Case 3 preferred portfolio represents a low cost, low risk and reliable set of resources for Utah residential and small business customers. Therefore, the Office does not recommend acknowledgment of the Re-optimized Case 3 portfolio without further analysis conducted by the Company. Such analysis would begin with applying the Company's new renewable resource policy criteria uniformly to the all 19 core portfolios (including Case 3) that were initially subjected to deterministic and stochastic testing. The results from this additional analysis should be provided to parties for further comment prior to the Commission's decision on whether or not to acknowledge the 2011 IRP.

A summary of the Office's concerns relating to the 2011 IRP process is given below.

- The public process was not conducted in a manner consistent with promoting the public interest. A credible IRP public process which provides sufficient opportunity for public input and information exchange must be maintained.
- The criteria for screening portfolios were changed in the final step of the selection process. These criteria need to be relatively consistent in IRPs and should not be modified without public input. In the 2011 IRP, the Company applied new criteria to a single portfolio (Case 3) in order to justify what appears to be a pre-determined portfolio result – the Business Plan (Case 19) which includes a full Energy Gateway transmission build out.
- All resources were not evaluated on a consistent and comparable basis. The Company did not evaluate geothermal and coal plants with incremental PCTs on a consistent basis with other resources.
- A consistent resource selection modeling approach was not applied to all cases. The replacement of geothermal with wind in the Re-optimized Case 3 preferred portfolio was based on an *ad hoc* analysis after extensive deterministic and stochastic IRP modeling was already completed.

The Commission should take a stronger active-directive role to address the concerns identified above and to ensure that the IRP public process is consistent with its IRP guidelines.

Finally, the Office recommends that the Commission order the Company to implement the following changes and requirements as listed below:

- Allow the IRP models to indicate the best combination of resources and transmission. To this end, the Company should apply its new renewable resource policy criteria uniformly to the all 19 core portfolios (including Case 3) that were initially subjected to deterministic and stochastic testing. The Company's selection of a preferred portfolio should be informed by the analytical results from this additional step. The results should also be provided to parties for further comment prior to the Commission's decision on whether or not to acknowledge the 2011 IRP.
- Prepare a more refined analysis of coal-related issues in modeling coal plant displacement scenarios. Require the Company to describe and document its proposal for modeling pollution control technologies as options in its IRP models.
- Provide more detail on how the Company intends to acquire the Class 2 DSM levels targeted in the IRP. Require closer coordination between the DSM program and the IRP process, particularly with respect to Class 2 DSM resources.
- Support appropriate levels of market reliance by an ongoing assessment of market depth and liquidity.
- Allow the long-term load parameters in the PaR model to vary until the Company fully justifies a new modeling approach where these parameters are set to zero. The Company should be directed to provide a technical statement from its vendor, Ventyx, explaining why Ventyx endorses this new approach, the implications of this change for risk analysis and whether this change has been recommended to and adopted by other clients.
- Implement the recommendations to improve load forecasting contained in the GDS 2011 IRP Load Forecast Report in Attachment 1.
- Prepare a new Wind Integration Study in connection with the 2013 IRP filing. Organize a Technical Review Committee to direct and evaluate work related to the Study and include expertise from Utah. Further, the concerns identified by Mr. Falkenberg in Attachment 2 should be analyzed as part of the Study.
- Use a PRM in the range of 13.5% -14.0% until the Company can support the use of a lower PRM. At a minimum, this would require the Company to produce evidence supporting a PRM adjustment that directly relates to reserve sharing associated with its operating system.
- Use the FERC price cap approach to value the impact of energy not served when comparing portfolios in the stochastic analysis.