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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
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Date: September 9, 2013

Re: In the Matter of the Acknowledgement of PacifiCorp's 2013 Integrated Resource Plan; Docket No. 13-2035-01

## 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) 2013 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.

This objective (and others) is codified in a set of IRP standards and guidelines, which the Commission published in 1992.[1] For over 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 relies on these IRP guidelines to determine whether to recommend acknowledgement of PacifiCorp's 2013 IRP.

The Office notes that there was substantial improvement in the public process for the 2013 IRP. The Company's outreach to stakeholders through its numerous meetings and sharing of data was significant. We appreciate the Company's efforts in this area during the 2013 IRP process.

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

## II. Acknowledgment

As discussed at greater length in our comments, the Company has not adequately demonstrated that its preferred portfolio represents a low cost, low risk and reliable set of resources for Utah residential and small business customers. In particular, the IRP does not comply with IRP Guideline 1. Therefore, the Office recommends that the Commission not grant acknowledgement of the 2013 IRP absent certain changes in the modeling of cases.

The Commission should direct the Company to redo the preferred portfolio selection process without the inclusion of manually derived transmission benefits from the System Operational and Reliability Benefits Tool (SBT) in the stochastic modeling (PaR) phase. Parties should have an opportunity to comment on the updated results prior to the Commission deciding whether to acknowledge PacifiCorp's 2013 IRP.

In addition to the Office's recommendation to not acknowledge the 2013 IRP at this time, we also provide comments on several issues. These issues include transmission benefit analysis (SBT), portfolio selection without SBT, the reduction in wind resources, the need and timing of specific Energy Gateway transmission segments, DSM acquisition targets, market reliance and planning reserve margin.

## III. Compliance with IRP Guidelines – Incorporating SBT Benefits

The Commission's IRP Guidelines provide direction to the Company and parties in a number of important areas. The Office asserts that the Company has not met one of the primary IRP guidelines.

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

The Company evaluated 19 core cases (C01 to C19) across five Energy Gateway transmission scenarios (EG1 to EG5). The transmission scenarios represent different levels of buildout of the Energy Gateway Project with EG1 representing transmission segments already completed or under construction, EG2 representing the addition of the Windstar-Populus transmission segment and at the extreme, EG5 representing the complete Gateway buildout. Each core case was coupled with each transmission scenario (for example, EG1-C01, EG1-C02, EG1-C03… EG2-C01… etc.) The Company selected Energy Gateway Scenario 2, Case 7 (EG2-C07) as its preferred portfolio.

The Office has significant concerns as to whether the selection of EG2-C07 as the preferred portfolio by the Company represents the optimal set of low cost, low risk resources for Utah customers. The principal issue relates to the inclusion of cost reductions (benefits) derived from the System Operational and Reliability Benefits Tool (SBT) for portfolios that incorporate transmission scenario EG2. The SBT is essentially an ad-hoc collection of spreadsheets that attempts to quantify incremental benefits of new transmission lines that are not captured in the system optimizer model analysis. Without the incremental SBT benefits, portfolios incorporating EG2 are not among the low cost group of portfolios. When the SBT benefits are removed from EG2 transmission scenarios, only portfolios utilizing transmission scenario EG1 are low cost (see comments in section IV below). Benefits developed using the new SBT are highly subjective in nature and are not comparable to the benefits and costs determined through the established System Optimizer (SO) and the Planning and Risk (PaR) models.

The SBT has never been used before in the IRP modeling process. In fact, the SBT is a work-in-progress. The Company is currently engaging stakeholders in a SBT Workgroup to promote technical understanding of the spreadsheet tool and also to receive input to improve and refine SBT metrics. Clearly, the SBT is not in the proper state of development or acceptance by stakeholders or the Commission to be a major factor in the selection of the IRP preferred portfolio.[2] Further, use of the SBT violates the Commission's IRP guideline that resources be evaluated "on a consistent and comparable basis."[3] This occurs because the SBT attempts to calculate a set of external benefits associated with certain transmission investments in a way that is not comparable to the calculation of benefits or costs associated with different resource options examined in the core IRP analysis. Since the different configuration of transmission options result in different generation decisions, transmission is being used as a "potential future resource" and the guidelines require comparable treatment.

## IV. Selecting a Preferred Portfolio without the SBT Benefits

Table 1 below incorporates information from the Company's final screening process (see tables 8.1 through 8.4 of the 2013 IRP). The risk-adjusted Present Value Revenue Requirement (PVRR) or cost of each of the top twelve performing portfolios is provided with the SBT benefit (from Table 8.1 of the IRP) and also without the SBT benefit. The costs in the column without SBT are calculated by adding $654 million to the PVRRs of

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[2] For example, using the SBT the Company has preliminarily identified $239 million of incremental "customer benefits" directly resulting from the Windstar-Populus (EG2) transmission line. According to the Company's February 27, 2013 IRP presentation, this benefit is derived from the avoidance of a 1-in-20 year outage event using 2002 CPI data to show the impact of momentary and sustained per-outage cost across customer classes. However, on the presentation slide the Company states, "How this metric should be applied is still being evaluated." In addition, the Company has calculated $149 million of incremental benefits associated with avoiding the White Horse - Mustang – Freezeout (White Horse) 230 kV line. However, it isn't clear from the Company's presentation whether a portion of this incremental benefit may have already been reflected in the benefits calculated by the System Optimizer model (see slide 11). The potential for a double counting of benefits is an issue that requires further investigation. There also may be specific benefits associated with the White Horse line that are lost if that transmission project is supplanted by EG-2. Whether and how these "lost benefits" were estimated and treated in the SBT analysis is another matter that requires additional discussion.

[3] IRP 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." PSC Order, June 18, 1992, Docket 90-2035-01.

the six EG2 portfolios.[4] The individual case rankings for other screening measures such as emissions and reliability (mean and upper-tail energy not served) are also included in Table 1.

**Table 1**
**Portfolio Costs ($m) and Rankings using $CO_2$ Scenario Averages**

| | With SBT Benefit | | Without SBT Benefit | | Rank | | |
|---|---|---|---|---|---|---|---|
| | PVRR | Rank | PVRR | Rank | $CO_2$ Emissions | Mean ENS | Upper Tail ENS |
| EG1-C03 | $33,537 | 5 | $33,537 | 3 | 3 | 7 | 2 |
| EG1-C07 | 33,775 | 8 | 33,775 | 4 | 6 | 11 | 11 |
| EG1-C11 | 33,931 | 11 | 33,931 | 5 | 2 | 2 | 3 |
| EG1-C15* | 33,293 | 1 | 33,293 | 1 | 1 | 1 | 1 |
| EG1-C16 | 33,536 | 4 | 33,536 | 2 | 4 | 4 | 5 |
| EG1-C17 | 34,014 | 12 | 34,014 | 6 | 11 | 12 | 12 |
| EG2-C03 | 33,542 | 6 | 34,196 | 9 | 5 | 6 | 6 |
| EG2-C07 | 33,483 | 3 | 34,137 | 8 | 7 | 8 | 9 |
| EG2-C11 | 33,924 | 9 | 34,578 | 11 | 8 | 3 | 4 |
| EG2-C15* | 33,425 | 2 | 34,079 | 7 | 10 | 9 | 8 |
| EG2-C16 | 33,558 | 7 | 34,212 | 10 | 9 | 5 | 7 |
| EG2-C17 | 33,924 | 10 | 34,578 | 12 | 12 | 10 | 10 |

***These cases were eliminated from consideration as explained below.**

With the inclusion of the SBT benefit, cases EG1-C15 and EG2-C15 are the lowest cost cases. These cases assume accelerated acquisition of Class 2 DSM and prohibit the selection of any new CCCT gas resources. The Company eliminated these cases as potential candidates for two reasons: the Company considers the DSM cost and ramp rate assumptions to be very uncertain; and the Company was uncomfortable excluding the possibility of adding a CCCT resource. Therefore, the Company chose case EG2-C07 as the basis for the preferred portfolio because it represented the lowest-cost (lowest PVRR) case remaining of the twelve top performing portfolios (with SBT).[5] The final preferred portfolio was manually modified to replace about 200 MW of wind resources needed for RPS compliance with Renewable Energy Credits (RECs) and is designated as EG2-C07a.

[4] See page 67 of the 2013 IRP. $1,165 million (Total Benefits) minus $511 (System Optimizer Analysis benefits) equals $654 million of benefits from SBT. The risk adjusted PVRRs of cases with EG2 in Table 1 above (column titled "With SBT Benefit") were manually lowered by this $654 million.

[5] The Office notes that measures other than PVRR cost are typically considered when evaluating candidate portfolios. Such measures include emissions, reliability and resource (fuel) diversity. Table 1 shows that EG2-C07 is a below average case when compared to the other 12 cases using measures such CO2 emissions, mean energy not served (ENS) and upper tail ENS.

As discussed earlier in our comments, the SBT benefits are not rigorously developed and should not be included in the decision process to select a preferred portfolio. When the SBT benefits are removed, the EG2 cases increase in cost by $654 million.[6] As Table 1 shows, the highest ranking portfolio in terms of cost without SBT is now EG1-C16, which has a PVRR that is $600 million less than EG2 C-07. Case EG1-C16 incorporates medium $CO_2$ and fuel prices and forces state RPS requirements to be met partly by geothermal resources. The Company's concern regarding geothermal development risk is alleviated because the geothermal resources are assumed to be priced as Power Purchase Agreements (PPAs) negotiated as a result of RFPs.

Table 2 below compares resources between the Company's preferred portfolios and case EG1 C-16. It is interesting to note that the resource mix is very similar. The primary differences between the C-16 and C-07 cases are the inclusion of geothermal resources and the early retirement of an additional coal plant (Cholla 1 - 387 MW).

**Table 2**
**Comparison of New Resources over 20 Years (MW)[7]**

| | EG2 C-07 | EG2 C-07a | EG1 C-16 |
|---|---|---|---|
| Net Coal | -1,698 | -1,698 | -2,085 |
| Gas Plants | 3,175 | 3,175 | 3,175 |
| DSM | 1,783 | 1,786 | 1,764 |
| FOTs | 1,205 | 1,209 | 1,235 |
| Wind | 858 | 650 | 600 |
| Geothermal | 0 | 0 | 145 |
| Other | 338 | 338 | 338 |
| Total | 5,661 | 5,460 | 5,172 |

The Office recommends that the portfolio based on EG1 C-16 containing geothermal resources be given serious consideration as the IRP preferred portfolio. Not only is EG1 C-16 lower cost, but it also ranks considerably higher than the Company's preferred portfolio (EG2 C-07a) in the areas of $CO_2$ emissions and reliability measures as reflected by mean ENS and upper tail ENS (see Table 1 above). With the inclusion of geothermal resources in the mix, it is also a more diverse portfolio compared to Case EG2 C-07a.

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[6] This is the Office's understanding of how the SBT benefits were applied and we are waiting for the Company's response to OCS DR #3 for verification.

[7] Data are a consolidation of detailed capacity expansion results. See Table 8.7 on page 227 of the 2013 IRP and pages 178 and 187 in Appendix K of the 2013 IRP. These are the expansion plan resources selected by the System Optimizer model without consideration of the SBT benefits.

## V. Reduction in Wind Resources and the Need for the full Energy Gateway

The amount of Wyoming wind resources in 2013 IRP preferred portfolio is considerably lower than in the 2011 IRP (see Table 3 below). The 2011 IRP and 2011 IRP Update included approximately 2,100 MW of wind resources that were manually selected by the Company to meet renewable resource objectives. In the 2011 IRP, the Company justified these wind acquisition targets on the basis that renewable resources mitigated fuel and carbon risk, regulatory compliance uncertainty and challenges in meeting long-run public policy goals.[8]

**Table 3**
**Wyoming Wind Resources in the Preferred Portfolio (MW)**

| Year | 2011 IRP | 2011 IRP Update | 2013 IRP |
|---|---|---|---|
| 2018 | 300 | 0 | 0 |
| 2019 | 300 | 225 | 0 |
| 2020 | 200 | 225 | 0 |
| 2021 | 200 | 0 | 0 |
| 2022 | 200 | 150 | 0 |
| 2023 | 200 | 100 | 0 |
| 2024 | 200 | 75 | 432 |
| 2025 | 100 | 200 | 218 |
| 2026 | 100 | 200 | 0 |
| 2027 | 100 | 200 | 0 |
| 2028 | 100 | 200 | 0 |
| 2029 | 100 | 250 | 0 |
| 2030 | | 250 | 0 |
| **Total** | **2,100** | **2,075** | **650** |

The sudden decrease in wind capacity from approximately 2,100 MW in the 2011 IRP to only 650 MW in the 2013 IRP, along with the deferral in the timing of wind acquisition from 2018 to 2024, was a surprising result given the recent emphasis placed on renewable resources by the Company in the 2011 IRP and IRP Update. Furthermore, the significantly lower wind resource totals in the 2013 IRP raise important questions regarding the timing and need for certain Energy Gateway segments and whether these incremental transmission segments can be demonstrated to be cost-effective for retail customers.

In our 2011 IRP comments, the Office pointed out the close interdependency between the acquisition of Wyoming wind and the full Energy Gateway transmission expansion. In the 2011 IRP, the Company clearly stated:

[8] PacifiCorp 2011 IRP, pages 205, 225-228.

> "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."[9]

Therefore, without significant acquisition of Wyoming wind resources (now reduced to 650 MW in the 2013 IRP), certain segments of the Energy Gateway Project may not be needed (Gateway West and South in Table 4 below). In particular, these resource changes introduce uncertainty as to whether the Windstar-Populus line is an economically viable project.

**Table 4**
**Wyoming Wind Transmission Buildout[10]**

| | Segment | Connection Points | Scheduled In-Service |
|---|---|---|---|
| Gateway West | D | Windstar-Populus | 2019-2021 |
| Gateway West | E | Populus-Hemmingway | 2020-2023 |
| Gateway South | F | Aeolus-Mona | 2020-2022 |

## VI. Acquisition of Class 2 DSM Resources

The Class 2 Demand Side Management (DSM-2)[11] resources from the 2011 and 2013 IRP preferred portfolios are compared in Table 5 below. As indicated in Table 5, planned DSM-2 resources have declined significantly since the 2011 IRP. Despite that reduction DSM-2 resources are expected to make up over 50% of planned new long term resources over the first 10 years of the planning cycle.

[9] PacifiCorp 2011 IRP Volume I, March 31, 2011, pgs 81-82.
[10] See page 74 of the 2013 IRP.
[11] Class 2 DSM resources are energy efficiency programs.

**Table 5**
**Preferred Portfolio Annual Class 2 DSM Capacity Resource Additions (MW)[12]**

| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 10-Yr Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2011 IRP | 111 | 118 | 122 | 124 | 126 | 120 | 122 | 125 | 125 | 133 | 1,226 |
| 2013 IRP | 114 | 116 | 103 | 101 | 97 | 92 | 90 | 80 | 79 | 81 | 953 |
| 2013 vs. 2011 | 3 | -2 | -19 | -23 | -29 | -28 | -32 | -45 | -46 | -52 | -273 |
| 2013 IRP LT Res* | 141 | 777 | 121 | 119 | 116 | 106 | 104 | 95 | 96 | 98 | 1,773 |
| DSM % of LT Res | 81% | 15% | 85% | 85% | 84% | 87% | 87% | 84% | 82% | 83% | 54% |

*LT Res = Long Term Resources

The Office continues to support the Company's pursuit of cost effective DSM resources. However, the Office is concerned about whether the Company can actually achieve these levels of DSM acquisition. For example, the Company's 2011 IRP Update included 47 MW of DSM-2 in Utah for 2012. The Company's 2012 DSM Annual Report estimates that only 42 MW of DSM-2 was achieved in Utah in 2012. Furthermore, the 2013 preferred portfolio targets 63 MW of DSM-2 in Utah for 2013. Thus, the goal for 2013 is 50% higher than what was actually achieved in 2012.

Since the Company relies heavily on the acquisition of DSM-2 to meet long term resource needs, any reduction or delay in the acquisition of this resource may require the Company to rely more on market purchases (additional FOTs), thereby putting customers at risk of higher prices. The Office recommends that whenever the Company seeks approval of a new or expanded DSM-2 program it should be required to report the amount of MW that will be contributed to the annual DSM targets identified in the IRP. The Office further recommends that the Company be required to provide regular updates to the DSM Steering Committee on the status of DSM-2 actually achieved and expected to be achieved, as it relates to the acquisition targets in the IRP.

## VII. Market Reliance – Front Office Transactions (FOTs)

Market reliance reflects the amount of short-term market resources or "Front Office Transactions" (FOTs) the Company relies on to meet annual peak load requirements. In

[12] See Table 8.16 of the 2011 IRP and Table 8.7 of the 2013 IRP. DSM Class 2 amounts in Table 5 above are the sum of East and West amounts from the tables in the IRP.

recent IRPs, the Company has relied heavily on FOTs to meet forecasted load requirements and this trend is continued in the 2013 IRP. In fact, FOTs dominate the annual resource additions until the acquisition of gas-fired and wind resources in the 2024-25 time period. Table 6 compares the annual FOT levels in the 2011 and 2013 IRPs. As the table indicates, the reliance on FOTs in the 2013 IRP is still considerable, especially in the years 2019-2022.

**Table 6**
**Preferred Portfolio Annual Front Office Transactions - FOTs (MW)**

| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|---|---|---|---|---|
| 2011 IRP | 1,429 | 1,190 | 1,149 | 775 | 822 | 967 | 695 | 995 | 700 | 750 |
| 2013 IRP | 650 | 709 | 845 | 983 | 1,102 | 1,209 | 1,323 | 1,420 | 1,191 | 1,333 |
| 2013 IRP vs. 2011 IRP | -779 | -481 | -304 | 208 | 280 | 242 | 628 | 425 | 591 | 583 |

In support of the significant amount of FOTs in its preferred portfolio, the Company provides an analysis (see Appendix J) of WECC's 2012 Power Supply Assessment (PSA). The 2012 PSA base projections for the Basin, Rockies, Desert Southwest, and Northwest sub-regions indicate adequate reserve margins for the summer period from 2014 through 2022. The Company concludes that there is both adequate market depth and liquidity in these sub-regions to maintain positive reserve margins for several years.

The Office has also reviewed the WECC 2012 PSA and arrived at a similar conclusion. However, because the Company almost exclusively relies on FOTs to meet incremental resource needs over the next decade, this is an issue that needs to be closely monitored. If abnormal conditions were to occur due to various factors (pro-longed drought, extreme temperatures, new climate change initiatives, etc.), this could stress certain sub-regions and ripple through the western interconnect.[13] It is not clear to the Office what specific contingency plans the Company has in place if market conditions quickly change in certain sub-regions resulting in upward pressure on prices. Such plans could be identified in the 2013 IRP Update (filed March 2014) and more fully vetted in the next IRP cycle.

[13]For instance, under extreme summer temperature conditions both the Northern and Southern California sub-regions would incur rapidly declining reserve margins, which could result in upward pressure on electricity prices at certain market hubs. Table 10 in the 2012 PSA illustrates the reserve margins by sub-region under extreme summer temperatures.

## VIII. Selection of the Planning Reserve Margin

The Loss of Load Probability Study (Study) conducted by Ventyx (Appendix I) was relied on by the Company to select a 13.0% (PRM) for IRP purposes. The Study compares $/MWh of Expected Un-served Energy (EUE) to a range of PRMs in order to determine the incremental cost of reliability. The Study shows that the incremental cost of reliability is relatively flat in PRMs ranging from 12.0% - 15.0% and sharply increases at a PRM of 16.0%, due to the need to construct a new large generating station.14

The Office has the following comments on the Study:

- Selection of 2014 for Study purposes. It is not clear from the Study why a single year – 2014 was selected to analyze the cost of reliability at different PRM levels. The Office notes that a large, east-side CCCT station is scheduled to come on-line in 2014, which should significantly improve reliability on PacifiCorp's system. It seems that 2016 would have been a better year to use because the large CCCT station targeted for that year in the 2011 IRP has been delayed to 2024 (see IRP preferred portfolio). Further, the Study doesn't explain why a single year rather than series of years was used and how that could possibly impact study results.
- NWPP Reserve Sharing. According to the Study, the ability to "tap" resources from the Northwest Power Pool (NWPP) increases the "actual" reserve margin by 3.1%. However, this reliability benefit is apparently reduced by the need to hold additional reserves to meet variability in wind generation; a factor that wasn't included the Study.15 Without knowing how wind variability affects $/MWh costs at different levels of reliability, it is difficult to assess whether reserve sharing would allow PacifiCorp to reduce its PRM below 13.0%.
- Utah-North Zone. The Study identifies the Utah-North zone as one area where most of the un-served energy appears. The Office notes that the Lakeside 2 CCCT plant (2014) and new transmission projects should improve reliability in the Utah-North zone. While maintaining a PRM of 13.0% (or higher) in recent IRPs may have positively impacted reliability for Utah customers at a low incremental cost to the system, the new transmission infrastructure and CCCT capacity should alleviate reliability concerns in the Utah-North zone.

Since the Company has not analyzed how current and future wind integration requirements impact available system and non-system (NWPP) reserves, it is difficult to

[14] Access to relatively inexpensive Front Office Transactions (FOTs) are the primary reason that incremental costs are flat between PRM levels ranging from 12.0% - 15.0% (see Figure 7). Increases in these assumed low prices for FOTs could appreciably increase the incremental costs of moving to a higher PRM level.
[15] 2013 IRP, Public Meeting on December 14, 2012, Company PRM Presentation, Page 4.

make an informed judgment about whether the Company's proposed 13.0% PRM should be raised, lowered or supported. Consequently, the Company's proposed 13.0% level is acceptable for this IRP, but the dynamic relationship between wind integration requirements, reserves available from the NWPP and location-sensitive reliability issues should be further studied.

## IX. Conclusion and Recommendations

As discussed at the beginning of these comments, the Company has not demonstrated that its preferred portfolio is the optimal set of low cost, low risk resources for Utah customers. Therefore, the Office recommends that the Commission not grant acknowledgement absent the Company performing a new analysis incorporating some changes in how the cases are modeled. Such analysis would involve removing the SBT benefits from the stochastic modeling phase and then redoing the pre-screening, initial screening and final screening preferred portfolio selection processes. 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 2013 IRP.

Without this additional analysis, the Commission does not have adequate evidence to acknowledge the Company's 2013 IRP as filed with the selected preferred portfolio.

A summary of the Office's concerns relating to the 2013 IRP is given below.

- The SBT is still a work-in-progress and should not be used as part of the IRP process for evaluating candidate cases and selecting a preferred portfolio.
- Absent the SBT benefits, case EG1 C-16 appears to be a superior portfolio to the Company's preferred portfolio, EG2 C-07a.
- There is a dramatic decrease in wind resources from the 2011 IRP to the 2013 IRP, which raises questions regarding the need for and timing of certain Energy Gateway West and South transmission segments (D, E, and F).
- DSM-2's share of long term resources in the preferred portfolio is significant (over 50%); therefore, the Company must demonstrate that this resource is achievable at these projected levels.
- The Company relies heavily on FOTs to meet growing resource needs and the Company appears to lack a specific contingency plan in the event that market supplies become tight and upward pressure is placed on market prices.
- The analysis to determine the appropriate Planning Reserve Margin (PRM) should be expanded to specifically identify both the ability to tap reserves from the NWPP and the additional reserves that are necessary to integrate wind resources.

Finally, the Office submits the following recommendations to the Commission:

- Order the Company to remove the SBT benefits from the IRP analysis and redo the preferred portfolio selection process.

- Prohibit the use of SBT benefits in any future IRP until more robust supporting evidence is provided showing the efficacy of its analysis. Further, any such analysis must be applied consistently across all scenarios and must result in a comparable analysis of benefits and costs as is conducted for other resource options.
- Require the Company to report how each new DSM-2 program contributes (in MW) to fulfilling the IRP targets at the time approval is requested. Also require the Company to report regularly to the DSM Steering Committee on the progress of existing DSM programs in fulfilling the near-term annual IRP targets.
- Require the Company to provide a contingency plan for the IRP's heavy reliance on FOTs to be used in the event that market supplies tighten and prices increase significantly. This contingency plan should be provided as part of the 2013 IRP update and addressed more fully in the next IRP cycle.
- Require the Company in its next IRP to explicitly identify the impact of NWPP reserve sharing and wind integration requirements on the PRM.