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November 3, 2009

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Oregon Public Utility Commission
550 Capital Street NE, Ste. 215
Salem, OR 97301-2551

Attn: Filing Center

RE: **Docket No. LC 47**
PacifiCorp's 2008 Integrated Resource Plan ("2008 IRP")
PacifiCorp's Response to Oregon Party Comments

Please find enclosed the original and one (1) copy of PacifiCorp's response to comments submitted to its 2008 IRP by Commission Staff, the Northwest Energy Coalition, and, joint comments of Renewable Northwest Project and Citizens' Utility Board of Oregon.

It is respectfully requested that all formal data requests regarding this filing be provided to the Company as follows:

By e-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
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Please direct any informal inquiries to Pete Warnken, Manager Integrated Resource Planning at (503) 813-5518 or Joelle Steward, Regulatory Manager, at (503) 813-5542.

Sincerely,

Andrea L. Kelly /JB

Andrea L. Kelly
Vice President, Regulation

cc: Service List for Docket No. LC 47

CERTIFICATE OF SERVICE

I certify that I have cause to be served the foregoing **Response** in OPUC Docket No. LC 47 by electronic mail and US mail to those parties who have not waived paper service on the attached service list.
DATED this 3rd day of November, 2009.

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Response to the Oregon Party Comments on PacifiCorp's 2008 Integrated Resource Plan

(Docket LC-47)

1. INTRODUCTION

PacifiCorp filed its 2008 Integrated Resource Plan ("IRP") with the Public Utility Commission of Oregon ("Commission") on May 29, 2009. The Commission will acknowledge an IRP that meets the procedural and substantive IRP guidelines and seems reasonable based on information available at the time of acknowledgment.[1] As part of the IRP acknowledgment schedule, the Commission invited parties to submit comments and acknowledgment recommendations by October 8, 2009. Four parties submitted written comments: Commission staff ("Staff"), the Northwest Energy Coalition ("NWEC"), and a joint submittal by the Renewable Northwest Project and Citizens' Utility Board ("RNP/CUB").

PacifiCorp is pleased to have the opportunity to provide this response document to the Commission, and is especially appreciative of RNP/CUB's comment that "*we believe PacifiCorp has once again engaged in an ambitious IRP analysis that is in some ways among the most sophisticated in the nation.*" This document addresses each the party's comments individually except in regard to the wind integration cost study. Since all parties took issue with the study, it is treated as a separate topic for discussion at the conclusion of this document.

2. EXECUTIVE SUMMARY AND RECOMMENDATIONS

Comments from parties in this docket primarily focus on the following issues: timing of resources given recent events, treatment of conservation resources, handling of carbon dioxide ("CO_2") regulatory impacts, and the wind integration cost study. PacifiCorp has fully complied with the Commission's IRP guidelines, and thus requests that the Commission fully acknowledge the IRP and the action plan.

A number of parties question whether the IRP has met certain guidelines. In these cases, the Company provides clarifications or explanations to show that it complies with the guidelines in question. PacifiCorp believes that none of the issues raised by the parties should serve as barriers to acknowledgment.

In the case of the wind integration cost study, the parties recommend that the Commission require PacifiCorp to conduct further work on the cost analysis. If the Commission agrees with the parties' recommendation, then the Company requests that such analysis not be used as a pre-condition for IRP acknowledgment. Similarly, if the Commission believes the Company should conduct additional analysis in other areas, the Company requests that the Commission provide

[1] See *Investigation Into Integrated Resource Planning,* Docket UM 1056, Order No. 07-002 at 10 (Jan. 8, 2007) *Re PacifiCorp's 2004 Integrated Resource Plan*, Order No. 06-029 at 1 (Jan. 23, 2006).

specific guidance in those areas while at the same time fully acknowledging this IRP and action plan.

3. RESPONSE TO STAFF COMMENTS

3.1. Addressing Recent Events in Portfolio Evaluation

Staff recommends that PacifiCorp conduct further analysis of its top ten portfolios with emphasis on the need and timing of resources given "the significant changes in customer load." Staff believes that the Company did not adequately support planned acquisition of the combined-cycle combustion turbine ("CCCT") in 2014 or the simple-cycle combustion turbine ("SCCT") resource in 2016 given decreased system loads.

PacifiCorp responded to the issue of the impact of the February 2009 load forecast on major resource timing in the Company's response to OPUC Staff Data Request 27 dated October 21, 2009.[2] In the response, the Company noted that based on the February 2009 load forecast, peak loads for the east side of the system *increased* relative to the November 2008 load forecast used as the basis for portfolio analysis. On a system basis, the peak loads declined by just 42 megawatts in 2014 and only 17 megawatts in 2015.[3] PacifiCorp also noted that the last paragraph on page 250 of the IRP mentions that the peak load changes are insufficient to change the timing of the CCCT. The Company appropriately accounted for the February 2009 load forecast, as well as the prospects for further near-term changes in forecasted loads, in the IRP action plan.

PacifiCorp also clarifies its expectations regarding Commission review, interpretation, and acknowledgment of the IRP action plan in light of volatile planning conditions that Staff cites in its comments. Action item number 3 designates a span of time—2012 through 2016—during which the Company intends to procure firm capacity and energy resources based on prospective evaluation of loads, market conditions, prices, and regulatory activity. PacifiCorp requests the Commission acknowledge this flexible acquisition strategy rather than specific resource acquisitions with exact dates (i.e., the CCCT in 2014 or the SCCT in 2016). While the preferred portfolio represents the least-cost, risk-adjusted forecast of resource needs, it reflects information and assumptions incorporated at the time the IRP was prepared. The IRP is not intended as a rigid resource acquisition schedule that the Company must match when it seeks to acquire the resources, through requests for proposals ("RFPs") or other means, at future points in time. This is stated in the introduction section of Chapter 9 in the IRP:

> *"However, it is important to recognize that the resources identified in the plan are proxy resources and act as a guide for resource procurement. Resources evaluated as part of procurement initiatives may vary from the proxy resource identified in the plan with respect to resource type, timing, size, cost, and*

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[2] OPUC Staff Data Request 27 – submitted to the Company on October 7, 2009 and responded to on October 21, 2009: "*In its sensitivity analysis on the preferred portfolio, using the February 2009 forecast, please discuss why the Company held the CCCT constant in the capacity expansion model. Why did the Company not allow this resource to be determined by the capacity expansion model in the same way that it did the SCCT? See page 10 of the IRP.*"
[3] See Table 8.46, page 250 of the IRP for a comparison of peak load forecasts.

> *location. Evaluations will be conducted at the time of acquiring any resource to justify such acquisition."*

Finally, PacifiCorp comments on Staff's expectation that recent events should prompt the Company to refresh its portfolio analysis irrespective of the complexity, time commitment, and existence of regulatory deadlines. State commission IRP scheduling orders, as well as new IRP analytical and modeling requirements imposed by the Oregon and Utah Commissions, constrained the scope of follow-up analysis that could be accommodated for this IRP. The Company explained this situation in response to OPUC Staff Data Request 28 dated October 21, 2009, attached as Exhibit 1. Even if the Company could accommodate more portfolio analysis as recommended by Staff, this would lead to a complete overhaul of the IRP given the vintage of the original modeling assumptions and calls by stakeholders to refresh as many assumptions as possible. Staff's proposal—by virtue of tying IRP guideline compliance to the vintage of data used—would require the Company to be in a continuous IRP development mode with the 2008 IRP update already underway and no Oregon acknowledgment prospects for the foreseeable future. The matter is also complicated by virtue of both Washington and Idaho having already acknowledged the IRP, thereby presenting the Company with the untenable situation of managing two different system-wide IRPs. PacifiCorp thus requests that the Commission reject Staff's proposal and allow the Company to update its portfolio analysis as part of the 2008 IRP update cycle.

3.2. The Linkage between Energy Gateway Project Transmission Project Planning and the IRP

Staff claims that PacifiCorp did not adhere to the Commission's IRP Guideline 5 by modeling the Energy Gateway Transmission Project ("Energy Gateway") as part of the base transmission system for resource portfolio development and evaluation. Staff argues that the Company should have treated Energy Gateway transmission as resource options that compete against other resources in the portfolio analysis because the Company seeks acknowledgment of near-term Energy Gateway action items.

The Company made the decision to go forward with the Energy Gateway project in 2007, and various Energy Gateway transmission segments evaluated for the 2007 IRP using the capacity expansion model were shown to be beneficial as part of resource portfolios even without accounting for congestion and grid reliability benefits. The first key segments of the project are now under construction and additional segments are in the rating and permitting phases.

PacifiCorp is seeking acknowledgment of the near-term Energy Gateway planning and construction activities in recognition that they are in progress and have been or are being studied, vetted and approved through numerous permitting and approval proceedings. The Company's 2008 IRP identifies the need for investment in major new transmission facilities to reliably meet the forecasted loads of PacifiCorp's customers. The Energy Gateway transmission upgrades were included in the 2008 IRP models, and the Company's resource decisions accounted for the impact of the Energy Gateway capacity. To the extent that the Energy Gateway configuration or timing of individual segments changes, those modifications will be addressed in subsequent analysis for the IRP and IRP updates, and reflected in revised IRP action plans.

In meeting the requirements outlined in Guideline 5, the Company points out the complexity and limitations of evaluating transmission options on a comparable basis with other resources in the context of the IRP modeling framework. The IRP models are not designed to evaluate the impacts of transmission investments on grid reliability, and are not set up to account for utilization beyond PacifiCorp's firm transmission requirements for meeting loads, which are fundamental aspects of the Energy Gateway project. Such evaluation is appropriately handled by the PacifiCorp transmission department's analytical models and other transmission planning tools. Consequently, the IRP framework is best suited to support investment justification for the Energy Gateway project, but is not sufficient for doing so. In this vein, the IRP models have been used to estimate system power cost benefits from adding Energy Gateway capacity as one input into broader financial analysis of the Energy Gateway investments conducted by the transmission department. For example, to support Energy Gateway investment analysis based on the 2008 IRP preferred portfolio, simulations with the Planning and Risk stochastic production cost model generated a 20-year net present value power cost benefit of $3.5 billion to $4.0 billion for serving PacifiCorp loads with Energy Gateway capacity included. The base case resource portfolio for this simulation study excluded all Energy Gateway transmission capacity additions and Wyoming wind resources that are contingent on the Energy Gateway capacity.

In terms of the broad context of Energy Gateway project justification, at the time of the acquisition of the Company by MidAmerican Energy Holdings Company (MEHC), many parties wanted to see the Company make transmission infrastructure investments. In addition, PacifiCorp's existing transmission system, as well as the transmission grid across the western region, is severely constrained, and numerous regional and sub-regional studies have identified the pressing need for investment in new transmission infrastructure. With little to no existing incremental capacity on the system, the Energy Gateway transmission development is essential to meet load growth, enhance transmission system reliability, and provide capacity to integrate renewable resources for the long-term benefit of customers.

Additionally, new federal standards that mandate increased transmission system reliability, along with PacifiCorp's recent operational experience, show that investing in PacifiCorp's transmission system is required to ensure the Company has the capability to provide reliable transmission service under expected operating conditions, and that the Company maintains the transmission system capacity necessary to deliver network load service and contractual point-to-point commitments. Increasing PacifiCorp's transmission capacity will also provide the opportunity for the Company to make off-peak energy sales, which are used to reduce overall power supply costs. Lastly, additional transmission capacity provides the Company added flexibility in the location and use of generating reserves and flexibility to perform required periodic maintenance on transmission lines with reduced risk to the interconnected transmission grid. All of the above help to reduce energy costs to customers.

The Federal Energy Regulatory Commission ("FERC") granted the Company incentive rate treatment, but equally important, the commission issued a 4-0 decision in which FERC stated:

> *"…we find that PacifiCorp has adequately demonstrated that the Project (with the exception of segment A) will ensure reliability and reduce transmission congestion… We find that segments B through H of the Project would establish for the first time a backbone of 500 kV transmission lines in PacifiCorp's Wyoming, Idaho and Utah regions.*

> *This would provide a platform for integrating and coordinating future regional and sub-regional electric transmission projects being considered in the Pacific Northwest and the Intermountain West, connection existing and potential generation to loads in an efficient manner, thus reducing the cost of delivered power. Also, the Petition cites the 2006 DOE National Electric Transmission Congestion Study and the 2004 Rocky Mountain Area Transmission Study in stating that that proposed Project will reduce congestion or maintain reliability in the Western Interconnection. Additionally, the project would establish a direct link between PacifiCorp's east and west control areas, providing numerous benefits including increasing transfer capability, reducing the need for curtailments, and reducing transmission congestion."*

The Company considers several factors before building new transmission facilities including the following:

- Current and future forecasts for energy demand (provided by system users) as specified from existing and new resources to new and existing loads. These considerations are addressed in the Company's 2008 IRP including demand side and energy conservation programs;
- Alternatives including building local generation near load and/or energy market purchases;
- The Company's use of existing land rights, existing rights-of-way, and corridors;
- Maximizing the transmission capacity installed in newly proposed rights-of-way and corridors;
- Upgrades to increase operability, and reliability from existing transmission lines and substations; and
- Maximizing the capacity and capabilities of existing facilities.

In conclusion, the Company believes a failure to acknowledge the near term Energy Gateway projects on the basis of rigid adherence to technical requirements in Guideline 5 ignores the complexity of transmission investment analysis, and would signal a lack of support for transmission investment that is critical to continuing to ensure safe, reliable, cost-effective electric service.

3.3. Updating the IRP Energy Efficiency Supply Curves

Staff claims that the Company failed to comply with IRP Guideline 6 (Conservation) because it did not incorporate the Energy Trust of Oregon's ("Energy Trust") latest energy efficiency potential study released on February 26, 2009. Staff further states that it "does not believe that PacifiCorp has yet demonstrated the maximum achievable energy savings from DSM related activities."

PacifiCorp reiterates its concern regarding Staff's expectation that IRP acknowledgment is contingent on PacifiCorp refreshing its portfolio analysis whenever new information becomes available at such a late stage in the IRP cycle. As mentioned above, such an expectation could ultimately lead to indeterminate IRP and regulatory outcomes as the Company's planning cycles are forced to overlap and state acknowledgment timelines continue to diverge.

PacifiCorp also points out that the Class 2 demand side management ("DSM") acquisition goal identified in IRP action item number 6 specifies the preferred portfolio cumulative peak capacity (900 megawatts) as an acquisition floor, anticipating that the Company would seek additional cost-effective conservation opportunities and continue to refine its DSM analysis as indicated in action item number 9. These two action items also include working with the Energy Trust to appropriately incorporate their latest potential study results into PacifiCorp's next IRP.

Regarding distribution efficiency improvements (i.e., voltage reductions), PacifiCorp has not conducted its own system-wide study to determine the potential, cost-effectiveness, and customer impacts of a voltage reduction program, and has not validated the Northwest Power and Conservation Council's ("Council") work in this area, which was performed by the consulting company, R.W. Beck, Inc. Until the Company completes such an analysis and determines how best to incorporate analysis results into the IRP, it is inappropriate to include voltage reduction as a resource in its current DSM acquisition goals.

3.4. Adequacy of Demand Response Resources for Oregon

Staff criticizes PacifiCorp for "the lack of application of DSM resources in Oregon", and states that the Company "needs to show an acquisition of DSM in Oregon that is on par with resource acquisition in the rest of the PacifiCorp territory or make the argument as to why these measures are not cost effective in Oregon."

PacifiCorp disagrees with Staff's premise that Oregon demand response resource acquisition (dispatchable load control, or Class 1 DSM) should be on par with other states. Pages 122 to 123 of the IRP explain resource cost differences between the east and west sides of PacifiCorp's system that are factored in the load area-based supply curves. For example, residential air conditioning load control in the west is nearly twice the cost of east-side programs due to climatic differences that lead to less control per installed switch. Class 1 DSM resources also provide more peak-shaving value in the eastern states due to steeper load duration curves.

PacifiCorp also disagrees with Staff's assertion that the Company did not account for Class 3 DSM (price responsive energy and capacity products) in the capacity expansion modeling used for portfolio development. As stated on page 122 of the IRP, PacifiCorp modeled a commercial curtailment product as a Class 1 DSM program, whereas for the 2007 IRP this product type was treated as a Class 3 DSM product and was excluded as a resource for preferred portfolio selection. To adopt other Class 3 DSM products as preferred portfolio resources, PacifiCorp requires more information on the extent to which these products could be sufficiently reliable to be classified as firm capacity resources, and has incorporated such research as part of IRP action item number 7 (Class 3 DSM).

4. RESPONSE TO NORTHWEST ENERGY COALITION COMMENTS

4.1. Changes in Resource Assumptions to Account for the Lake Side II Construction Termination Decision

NWEC criticizes PacifiCorp for updating its portfolio analysis to include the impact of the Lake Side II CCCT construction termination decision and changes to front office transaction availability assumptions, while not updating other assumptions such as the load forecast, capital costs, and gas costs. PacifiCorp is also criticized for "hard-wiring" the Lake Side II CCCT in the portfolios and thereby not testing whether the capacity expansion model would have picked this resource. NWEC claims that as a result, a CCCT could have been postponed further or avoided altogether.

PacifiCorp addressed the issues of conducting a comprehensive portfolio update and the impact assessment of the February 2009 load forecast in its response to Staff's comments (See Section 3 above). In short, the Company appropriately updated the IRP portfolio analysis given its filing deadlines and analytical requirements, and accounted for the impact of the new load forecast and forecast uncertainty in the IRP action plan.

Regarding the handling of the Lake Side II CCCT in the portfolio analysis, PacifiCorp notes in the IRP that some fixing of a CCCT resource in capacity expansion model runs is necessary because the model does not account for resource optionality and reserve holding value captured through stochastic production cost modeling, and tends to favor SCCTs over CCCTs for meeting capacity planning reserve margins as a result.[4] The Company developed portfolios with the CCCT fixed, as well as based on treatment of the CCCT as a resource option. The stochastic production cost performance assessment clearly indicated that inclusion of the east-side CCCT in the portfolio resulted in a better cost outcome for customers. Consequently, NWEC's criticism that all of the Company's portfolio choices hardwired the Lakeside II CCCT is incorrect.

To address the comparability issue between the capacity expansion and stochastic production cost models regarding gas resource real option value, the Company intends to investigate cost adjustments to System Optimizer resources that would put them on an equal footing with the comparable resources modeled with the stochastic production cost model. If successful, this would avoid the need to manually fix CCCT resources in System Optimizer portfolios.

4.2. Comparison of PacifiCorp and Northwest Power and Conservation Council Energy Efficiency Potential Estimates

NWEC classifies as a "significant error" the existence of differences between energy efficiency potentials reported by PacifiCorp and the Council, and asserts that "there is no reason to think that the non-NW states served by PacifiCorp would have much less EE [energy efficiency] potential than the NW surveyed by the Council."

In response to this issue raised by NWEC and other parties at the Commission's October 8, 2009 public technical workshop on PacifiCorp's IRP, the Company distributed to members of the Oregon Docket LC 47 service list, a document describing the high-level differences between these potential estimates. (See Exhibit 2 attached). The main differences in potentials cited relate to study timing differences, the classification and treatment of certain energy efficiency measures (e.g., distribution energy efficiency), and the cost-effectiveness methodology and thresholds applied. Such differences do not constitute errors, but rather point to topics that should be discussed with the Council as the region seeks to better align energy efficiency planning processes.

[4] PacifiCorp 2008 Integrated Resource Plan, Chapter 8, page 235.

NWEC and other public stakeholders should also be aware of the distinction between conservation targets designed to attain a regional goal versus what can actually be realized on an individual utility basis. Conservation targets may be heavily influenced by each utility's load characteristics, retail prices paid by consumers evaluating various conservation options, and state regulatory policies. NWEC should not presume that the Council's potential study and conservation acquisition targets can be directly applied in all of PacifiCorp's service areas.

4.3. Sufficiency of PacifiCorp's Analysis of the Oregon Carbon Dioxide Hard Cap Portfolio

NWEC believes that PacifiCorp conducted insufficient analysis of the portfolio developed to simulate Oregon's CO_2 reduction targets (the Oregon "Hard Cap" portfolio), and goes further to state that the Company violated the Commission's requirement to develop a "compliant portfolio that meets the Commission's best cost/risk standard"[5] by not subjecting this portfolio to the cost and risk analysis used to evaluate other candidate portfolios.

NWEC is incorrect regarding the extent of the portfolio analysis performed for the Hard Cap portfolio (designated as "Case 40"). The last paragraph on page 193 of IRP summarizes the stochastic portfolio performance measure results:

> *"The stochastic costs results for the test simulation are as follows: mean PVRR of $41.0 billion, upper-tail mean PVRR of $76.4 billion, and production cost standard deviation of $11.7 billion."*

As this statement shows, NWEC is incorrect that the Company did not subject the Hard Cap portfolio to the cost and risk analysis used to evaluate other portfolios.

More importantly, in this paragraph the Company noted various study design issues and current technical modeling limitations associated with simulating a hard cap scenario applicable to an individual state. As a result, the cost and risk analysis results were considered preliminary and not suitable for direct comparison with those of other portfolios for preferred portfolio selection.[6] Future System Optimizer enhancements, along with a technique to employ System Optimizer's incremental emission cost data in the Planning and Risk model, will greatly improve future studies of this type.

4.4. Valuing Resource Flexibility in the IRP

NWEC criticizes PacifiCorp's IRP because it does not rely on a true dynamic modeling approach that mirrors real-world investment decisionmaking, and thus undervalues conservation and flexible, short lead-time resources such as market purchases. To remedy this criticism, NWEC suggests the Company utilize the portfolio modeling approach used by the Council. In a nutshell, this approach iteratively refines a single starting-point resource portfolio, accounting for the opportunity to abandon resources at various decision points during resource construction. This approach captures the so called "optionality value" of different resources.

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[5] Public Utility Commission of Oregon, Order No. 08-232, Docket LC 42, Additional Action Item no. 6, page 36.
[6] The biggest problem resulting from the System Optimizer's current limitations is that Oregon's hard cap must be enforced across PacifiCorp's entire service territory.

NWEC has identified dynamic modeling and treatment of resource optionality as a perceived methodological weakness for the past several integrated resource planning cycles. PacifiCorp's modeling framework, *along with annual updating of the IRP*, sufficiently captures the optionality value of different resources without sacrificing the focused modeling necessary to plan for the Company's specific future resource needs.

The representation of investment behavior under uncertainty in long-term resource modeling should be viewed in light of how integrated resource planning works in practice. The integrated resource planning process is itself a dynamic planning framework that accounts for the impacts of uncertainty on a rolling annual basis. The resource plan and associated action plan are refreshed every year with the most current available information and forward view of market conditions and risks; the IRP evolves methodologically to keep pace with structural trends in the industry and regulatory environment. Therefore, the actual outcome of PacifiCorp's integrated resource planning process is a plan that is continuously being adapted to changing circumstances.

NWEC inaccurately alleges that the process is a static long-term resource plan with no opportunity to change course. A good example of how PacifiCorp's IRP adapts to changing circumstances is the treatment of the planned Lake Side II CCCT in the 2008 IRP. In response to worsening economic conditions and other factors, the Company terminated the Lake Side II CCCT construction contract and refreshed its portfolio evaluation to account for removal of this 2012 resource. The real-world outcome (the planned deferral of a CCCT to at least 2014) mirrors what the Council's model tries to simulate. PacifiCorp notes that if the IRP cycles were at least as long as the five-year Northwest Power and Conservation Council's Power Plan ("Northwest Power Plan") development cycle, there would be a stronger argument to incorporate investment irreversibility as a decision criterion in the resource analysis framework.

NWEC claims that PacifiCorp's method of developing optimized portfolios with alternative input assumptions and subjecting the many portfolios to stochastic simulation is an inadequate risk assessment because only "fixed futures" are tested and stochastic input values "all regress to the base assumption." NWEC points to the Council's portfolio modeling approach as being superior to PacifiCorp's approach in this respect.

PacifiCorp acknowledges that the Council's modeling approach contains certain useful features, including the ability to simulate dynamic investment decision-making behavior. However, the combination of capacity expansion optimization (with many input assumption scenarios) and the Monte Carlo production cost simulation contained in PacifiCorp's methodology, sufficiently captures the optionality value of different resources, as does similar methodologies used by other electric utilities. The purpose of the Monte Carlo simulation is to subject a resource portfolio to conditions against which it was not originally optimized. Also, contrary to NWEC's claim, stochastic values do not converge to their expected values due to the inclusion of long-term volatility parameters in the stochastic model that generates the Monte Carlo variable draws.

Additionally, the Company points out that the Council's dynamic programming concept (while useful and feasible in the context of an aggregated regional representation of the electricity system) is not realistic from an implementation standpoint unless significant sacrifices of other modeling capabilities are accepted. It is simply not practical for PacifiCorp to adopt the Council's dynamic modeling functionality. The Company is not aware of any commercial planning models suitable for integrated resource planning that incorporate dynamic modeling functionality similar to the Council's methodology, nor is the Company aware of any electric utilities that have adopted this approach for their integrated resource planning development. PacifiCorp believes the absence of utilities utilizing this approach is indicative of the complexity and difficulty of implementing such a methodology, in light of many other competing model features required by utilities to meet their planning needs. The implication is that adding dynamic investment simulation functionality would entail compromises elsewhere in the modeling.

NWEC proposes two remedial solutions to cure their claim that PacifiCorp's IRP falls short of addressing investment decision-making under uncertainty. First, as a short-term fix, NWEC suggests that PacifiCorp allow its capacity expansion model to only select a single resource type, such as front office transactions or a combined-cycle combustion turbine plant, after eight to 10 years. While not addressing NWEC's resource flexibility issues, NWEC suggests this approach helps to prevent resource investments in the out-years from unduly influencing the model's near-term resource decisions. Second, NWEC proposes that the Commission require PacifiCorp to include "an 'inflexibility adder' or other mechanism to reflect the added risk that long-lead-time, capital intensive projects impose on the utility, if it is impossible for the Company to move to a dynamic methodology such as the Council's."

NWEC's proposed remedial solutions are flawed and violate IRP rules and regulators' expectations for analysis of energy and environmental policies. PacifiCorp has focused on out-year simulation due to new integrated resource planning requirements to expand the number of resource options, new state energy and environmental policies that impact resource decisions up to 20 or 30 years in the future, the effort to align the IRP with the Company's 10-year business plan, and the general challenges of forecasting that far into the future. These are issues facing all organizations that prepare long-term resource plans. While PacifiCorp believes there is value in investigating changes to out-year modeling (including improvements to scenario risk assessment), limiting out-year resource options to a single type is not a reasonable course of action because it would violate IRP rules requiring analysis of different resource options and the impacts of state and federal regulatory policies. Modeling a single resource type for long-range resource optimization would conflict with such rules.

Regarding the proposal to require an inflexibility adder, the Company views implementation of such a resource cost penalty as unnecessary because of the reasons stated above. In addition, estimating and defending the reasonableness of such a cost adder—a highly controversial idea to begin with—would require developing a new resource investment model or adopting the Council's model as another portfolio evaluation tool. Accommodating another model would require sacrificing other important integrated resource planning modeling activities and add to what NWEC already criticizes as the "labyrinth of details" included in the IRP.[7]

4.5. PacifiCorp's Portfolio Scoring System

NWEC claims that the portfolio performance scoring criteria ("performance measures") and associated importance weights are arbitrary and not reflective of customer concerns. Specifically, NWEC makes the following criticisms:

[7] Comments of the NW Energy Coalition dated October 8, 2009.

- Two of the performance measures—customer rate impact and production cost standard deviation—are not valid risk metrics because they fail to address the risk of worst-case outcomes, which is of most importance to customers. In the case of customer rate impact, this measure encompasses the impact of downward cost changes, which is a benefit to customers, while in the case of the production cost standard deviation, year-to-year cost variations are "mostly a management concern."
- The $0, $45, and $100 CO_2 tax scenarios are weighted equally.
- No scoring weight is given for optionality.
- No scoring weight is given for total CO_2 emissions.

First, PacifiCorp's performance scoring methodology is not arbitrary. Utility integrated resource planning, like any multi-criteria decisionmaking process, necessarily involves subjective determination of what measures are most important for judging the overall merit of resource portfolios. For this reason, PacifiCorp informs its decision making process with input from integrated resource planning process participants, and must also account for Company and regulatory concerns.

In addition, the Company aligns its integrated resource planning process with PacifiCorp's business planning process. This alignment is supported by stakeholders and is a requirement of the Public Service Commission of Utah. While the risk of high-cost outcomes is an important criterion, aligning the IRP and business plan must recognize other portfolio considerations such as affordability, timing of asset acquisition to lessen rate impacts, financing limitations, and credit rating implications. It is for these reasons that the rate impact measure has been given a significant importance weight, and the 10-year capital cost was added as a performance measure.

NWEC claims that the rate impact measure inappropriately factors in cost decreases. The Company notes that the year-to-year rate impacts are always increasing because resources are continuously being added to portfolios in response to load growth, new regulatory requirements, and contract expirations. Even if there were a mix of positive and negative annual rate impacts, this would in no way diminish the usefulness of the measure for portfolio comparison purposes.

PacifiCorp strongly disagrees with NWEC's claim that cost volatility should not have a role to play in portfolio selection, and believes that the Company's regulatory stakeholders would agree. Most utilities that use Monte Carlo simulation or similar stochastic modeling rely on some measure of cost variability in portfolio outcomes, such as standard deviation or coefficient of variation. Such risk measures have been accepted by state utility commissions, and in the case of Oregon, is mandatory for inclusion in IRPs.[8] PacifiCorp's weighting assignment of five percent to the production cost standard deviation reflects an appropriate emphasis on variable cost unpredictability in light of the other cost and risk measures adopted for portfolio preference scoring.

Second, NWEC erroneously claims that PacifiCorp weighted the three CO_2 tax levels the same for portfolio evaluation. Although straight-average present value revenue requirement ("PVRR") results using the three CO_2 tax levels were reported in the IRP, as explained in

[8] The Commission's IRP rules require utilities to include, at a minimum, "two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes." (IRP Guideline 1c.1, Order No. 07-047)

Chapter 7 (pages 169 to 170), the Company applied probability weights to the tax levels to create weighted-average PVRR cost measures, reflecting an expected-value CO_2 tax range of $15 per ton to $70 per ton. PacifiCorp evaluated portfolio performance over this range of expected-value CO_2 tax levels and did not rely on equal CO_2 tax weightings or a specific CO_2 tax level to select the preferred portfolio.

Third, NWEC's proposal to adopt an optionality measure and associated importance weight for portfolio ranking appears to be at odds with the Commission's requirement to treat resources on a consistent and comparable basis. The only feasible way to implement a portfolio-level optionality measure with PacifiCorp's IRP models is to rank order portfolios on the basis of generation shares by resource type, with favored short-term resources ranked ahead of CCCTs and other long-lead-time assets. Assigning resources a priority order on this basis reflects qualitative preferences that cannot be supported through the IRP modeling results.

Finally, NWEC's recommendation to include total CO_2 emissions as a measure for portfolio performance scoring has merit, and should be addressed in a public meeting for the next IRP. Consideration would need to be given to this measure's relationship with presumed cap and trade rules, including the treatment of offsets and safety valve provisions. The new model enhancements designed to more accurately characterize the Company's emission footprint should also give PacifiCorp more confidence in relying on such a measure for portfolio scoring in the future.

5. RESPONSE TO THE RENEWABLE NORTHWEST PROJECT AND CITIZENS' UTILITY BOARD COMMENTS

5.1. Treatment of Greenhouse Gas Emissions

RNP/CUB commends PacifiCorp on the scope of its CO_2 emissions modeling, and offers a number of recommended improvements:

- The carbon intensity graph presented in the IRP (pages 9 and 241) is not important information, because reducing absolute CO_2 emissions is the stated public policy goal. A more useful graph would be to show total CO_2 emissions on a year-to-year basis for the preferred portfolio.
- The $45 per ton CO_2 tax, which serves as the assumption for developing the preferred portfolio, is not sufficient for reducing overall CO_2 emissions on a long-term basis according to PacifiCorp's quote from the Electric Power Research Institute's CO_2 price impact study: "...it takes a CO_2 price of roughly $50/ton to flatten the growth of emissions over time..." (IRP, page 143). As stated by NWEC in their comments, this is at odds with the policy goal to reduce emissions to less than an historical base level.
- The IRP analysis does not account for the possibility of coal plant retirement, and should refine its modeling to account for scenarios where plant retirement becomes economic or a regulatory requirement.
- The Company may not have fully undertaken a trigger point analysis as required by the new CO_2 guidelines (Order No. 08-339). While the Company provides PVRR information on substitute portfolios, the IRP "does not explicitly address how the substitute portfolio's expected cost and risk performance compares to that of the preferred portfolio."

PacifiCorp agrees that a graph showing CO_2 emissions for the preferred portfolio and possibly other portfolios would be helpful to readers. Such a graph will be provided in the next IRP.

Regarding CO_2 emission trends under a \$45 CO_2 tax, PacifiCorp does not position the \$45 value as a base case assumption in the IRP. In deriving a preferred portfolio, use of the \$45 value along with other input assumptions yielded a portfolio that performed well across a spectrum of assumed CO_2 cost values and stochastic variable outcomes. With many CO_2 policy questions and program design issues having yet to be resolved—including the basic issue of the extent to which use of existing fossil fuel resources should be restricted—the preferred portfolio is deemed a reasonable starting point for subsequent resource planning efforts. The Company refers parties to the alternate resource acquisition strategy in Table 9.3 of the IRP (pages 270 to 271) tied to a "high cost impact" CO_2 regulatory future. As indicated, the case 17B portfolio, developed with a \$70 CO_2 tax, supports this alternative acquisition strategy.

On the subject of coal plant retirements, PacifiCorp agrees that it should refine its modeling to account for coal plant retirement scenarios. In 2008 the Company acquired a version of System Optimizer that includes improved handling of plant retirements and an "emissions module" with the capability to model a variety of unit betterment options. PacifiCorp is now in the process of testing the model's plant retirement/capacity replacement capabilities.[9]

PacifiCorp disagrees with RNP/CUB on the sufficiency of the cost and risk information provided for comparison of the preferred portfolio with substitute portfolios. Appendix B of IRP Volume II provides tables that report portfolio performance for all the stochastic cost and risk measures used in the IRP (pages 195 to 202). This appendix also provides tables showing the portfolio measure rankings and preference scores based on the probability-weighted CO_2 tax levels that range from \$15 to \$70 (pages 203 to215).

5.2. Portfolio Development Using a Fixed Future

RNP/CUB proposes that PacifiCorp modify the portfolio development approach by conducting capacity expansion optimizations in two passes: simulations to determine near-term resources to link to the IRP action plan, followed by simulations with the near-term resources fixed but allowing System Optimizer to optimize resources in the out years. This proposal is along the same lines as the dynamic modeling favored by NWEC, and addresses the perceived weakness of conducting scenario analysis with fixed futures.

PacifiCorp provided a detailed explanation and defense of its current IRP process and modeling framework in response to NWEC portfolio modeling criticisms (Section 4.4). The Company refers parties to this section for comments on why dynamic modeling and RNP/CUB's two-phase optimization strategy is not necessary to capture adaptive planning benefits in the IRP process.

The Company also points out that while the RNP/CUB proposal has some intuitive appeal, it would dramatically increase the number of System Optimizer runs and corresponding stochastic production cost simulations to an unrealistic level. Only by severely cutting back the number of

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9 Testing to date indicates that running plant retirement scenarios could increase model run-times by up to nine times greater than experienced with the simulations conducted for the 2008 IRP.

futures (or "cases") examined could this approach be implemented successfully. PacifiCorp would be willing to revisit this proposal with stakeholders once alternative CO_2 and renewable energy regulatory scenarios can be eliminated from the modeling process. In this case, the two-phase optimization approach would focus on different wholesale electricity and natural gas price futures.

5.3. Distinguishing between Top-Performing Portfolios on the Basis of Renewable Resource Content

RNP/CUB suggest that the competition between the two top candidate portfolios with different wind resource quantities could have been swayed towards the portfolio with more wind (Case 8), had PacifiCorp used a more accurate wind integration cost assumption.

PacifiCorp addresses RNP/CUB comments on the wind integration cost study in the next section. The Company does not agree that a more accurate wind integration cost assumption translates into a lower cost assumption for reasons explained below. PacifiCorp reemphasizes that one of decision criteria for choosing between the two portfolios was the magnitude of near-term capital expenditures associated with the more ambitious wind development program. With lower revenue projections and large capital expenditures needed to support load growth and plant emission reductions, resource affordability becomes a concern.

The Company notes that several wind integration cost studies commissioned by utilities rely on scenario analysis due to uncertainties in study assumptions. The Bonneville Power Administration and other regional utilities are grappling with how to anticipate the impacts and timing of operational advances in integrating wind resources while tackling the more complex aspects of measuring reserve requirements with finer granularity. The implication is that there is much more study work and definition of best practices that is necessary to refine cost estimates to the point where they can be considered accurate under a given set of resource planning assumptions. The IRP analytical focus has been, and will continue to be, on the public policy uncertainties that can dramatically impact the Company's renewable acquisition strategy, such as the status of the production tax credit and the impact of resource portfolio standards and CO_2 legislation. Consequently, as a matter of priorities, wind integration cost accuracy should have little bearing on preferred portfolio selection or the amount of renewables targeted for long-term acquisition.

5.4. Wind Capital Cost Assumptions

RNP/CUB is concerned that PacifiCorp appears to have selectively updated resource capital costs in response to the economic crisis, but excluded an update for wind turbine costs declines cited in the IRP (page 99). NWEC also raises this concern.

PacifiCorp points out that the reference to price trends on page 99 refers to both wind turbines and other resource types ("other power plant equipment"). Therefore, no resource was subjected to a price update at the tail end of the IRP process; wind and other resources were treated on a comparable basis for cost estimation purposes.

6. WIND INTEGRATION COST STUDY

All three parties expressed concern about PacifiCorp's wind integration cost study. RNP/CUB and NWEC objected to the study on the basis that the Company did not consider the joint variability of wind and loads, which would mitigate the need for some reserves. RNP/CUB also believe that PacifiCorp overstated reserve requirements by assuming that existing and new wind resources are 100 percent correlated, and that the Company erroneously assumed that all energy imbalances are settled through market transactions. Finally, RNP/CUB ties the implications of the wind integration cost study to rate-setting for Oregon's Transition Adjustment Mechanism ("TAM"). Both Staff and RNP/CUB recommend that the Commission not acknowledge the wind integration cost study. Staff proposes that the Commission require the Company to conduct further public workshops prior to the filing of the 2008 IRP update to fully vet the cost methodology, while RNP/CUB recommends that the Commission mandate the Company to complete an updated study "within 3 months of the close of this docket."

PacifiCorp does not dispute the contention that incorporating load variability into the cost analysis framework affects estimated reserve costs, and agrees to do so for its next wind integration cost update. However, due to the implications to its operational practices and the Western Energy Coordinating Council ("WECC") requirement to hold sufficient reserves, the Company has been careful to not extend the cost analysis to areas that require more research. For example, in addition to consideration of "load net of wind" impacts, the Company sees the need for more analysis on the impacts of transmission constraints and wind ramping events. These latter two factors could more than offset cost reductions resulting from the analysis improvements recommended by RNP/CUB. Focusing on only those changes that favor wind development could thus yield significantly underestimated wind integration costs and reserve requirements. A Commission requirement to expand the current wind integration cost study should thus recognize the need for a more comprehensive treatment of cost factors—a major undertaking for the Company. The Company appropriately used the most current and reliable information available to develop the wind integration cost study. PacifiCorp therefore does not believe that IRP acknowledgment should be made contingent on completing this study.

Regarding the reliance on markets for balance, the Company points out that given a set of market conditions, PacifiCorp's system is pre-scheduled to meet load and operating reserve requirements at the lowest cost within the operational limitations of available transmission and generation assets. Due to the variable nature of wind generation, sudden changes in wind production can require the system to be rebalanced to minimize operating costs under this new set of conditions. When this rebalancing occurs due to a change in available resources (i.e. wind production), it is important to recognize that PacifiCorp's owned generation assets have already been optimally scheduled to operate within the parameters of then-current market conditions. Consequently, the available resources that are "in the money" (operating costs are lower than market prices) and can be delivered to a market, are either operating at full available load or are being backed off to maintain the appropriate level of operating reserves required for system reliability.

For those resources at full available load, there is no incremental generation that can be called on to offset a sudden decline in system wind production. Similarly, resources that have been backed-off for reserve holding purposes cannot be ramped-up without violating operating reserve requirements and sacrificing system reliability. Therefore, the amount of energy lost with a drop in wind production can be met by either making a market purchase, subject to transaction costs reflective of then-current market conditions and required volumes, or by dispatching an out-of-the money resource that has operating costs that exceed market prices inclusive of any transaction costs. In either case, the cost to rebalance the system is higher than it would have been had the wind production not changed. Based on the Company's real time operating experience, this cost can be up to 25 percent above the market price. The premium is larger for more substantial transactions (i.e. above 200 megawatts) and decreases for smaller transaction volumes (i.e. below 100 megawatts). PacifiCorp's wind study supports the cost estimates include in the IRP.

7. CONCLUSION

PacifiCorp again expresses appreciation for the comments received by the parties. As described above, the Company's IRP fully complies with the Commission's IRP guidelines and is reasonable based on available information. If the Commission agrees with the parties' recommendation to require PacifiCorp to perform further analysis on wind integration costs, the Company requests that such analysis not be used as a pre-condition for IRP acknowledgment. The Company respectfully requests that the Commission fully acknowledge the Company's IRP and action plan.

EXHIBIT 1
PacifiCorp Response to OPUC Staff Data Request 28

LC-47/PacifiCorp
October 21, 2009
OPUC Data Request 28

OPUC Data Request 28

In its 2007 IRP the Company discusses its use of an updated load forecast from March 2007 that it was able to use for its IRP analysis. The Company believed it was prudent to use an updated forecasted due to the potentially significant changes in load associated with Wyoming. That same year, the Company filed its IRP in Oregon on May 30, 2007. With regard to the 2008 IRP the Company had a February 2009 load forecast, and filed with the Oregon Commission on May 31, 2009 of that year. Please discuss why the Company believed it was necessary to use an updated forecast in the 2007 IRP, but not now for the 2008 IRP. Please provide an explanation that takes into consideration the fact that the timing of the filing was the same in Oregon in both instances, yet this year you were not able to accommodate this updated load forecast in your analysis.

Response to OPUC Data Request 28

To ensure that the 2008 IRP was filed with all state commissions in compliance with their scheduling orders, conducting a complete portfolio analysis using the February 2009 load forecast—in effect refreshing the modeling and risk analysis process outlined in Figure 7.1 of the 2008 IRP (page 135)—was not possible. While the time between updated load forecast availability and the report filings is nearly the same for the two IRP cycles, the scope of the 2008 IRP modeling and analysis effort was significantly larger than that for the 2007 IRP. The major scope differences are summarized below:

- For the 2007 IRP, PacifiCorp evaluated a total of 17 portfolios, five of which were developed in response to the March 5th 2007 load forecast and other reasons highlighted in the IRP (See page 153 of the 2007 IRP, including footnote no. 53). In contrast, the 2008 IRP involved the evaluation of 57 portfolios, with 10 developed to address the impact of the decision to terminate the Lake Side 2 gas combined cycle construction contract on February 11, 2009. The over three-fold expansion in the number of portfolios reflects the new Oregon Commission carbon dioxide risk assessment guidelines (Order No. 08-339) as well as stakeholder expectations for larger coverage of key forecast variable combinations.
- The complexity and time requirements for model data preparation, operation, and output processing increased considerably with the introduction of energy efficiency supply curves and many other new resource types in the 2008 IRP.
- PacifiCorp was required to more thoroughly address its IRP requirement for "acquisition path analysis". The additional analysis was performed after the 2008 IRP preferred portfolio was selected, an activity that did not occur for the 2007 IRP.

While the increased IRP workload and filing deadlines precluded refreshing the entire portfolio analysis with the February 2009 load forecast, nevertheless, the Company used its load forecast sensitivity analysis to determine if the forecast would have a material impact on major resource decisions. (PacifiCorp's response to OPUC 1.27 indicates that it did not). On this basis, the February load forecast was included in the 2008 IRP.

EXHIBIT 2
Preliminary Comparison of PacifiCorp and Northwest Power and Conservation Council Energy Efficiency Potential Estimates

The PacifiCorp IRP and draft 6th NW Power and Conservation Council Power Plan ("Power Plan") share a number of common features as planning documents for delivery of electric services, but any comparisons between the two, even when geography/territories are accounted should be viewed as illustrative only.

The purpose of the IRP is contained in the first sentence of the Executive summary, "PacifiCorp's 2008 Integrated Resource Plan (2008 IRP), representing the 10th plan submitted to state regulatory commissions, presents a framework of future actions to ensure PacifiCorp continues to provide reliable, reasonable-cost service with manageable risk to its customers." The limitations of the Power Plan with respect to comparisons to a utility-specific IRP are described in the summary of the plan, "The Plan is not a plan for every individual utility in the region, but instead is intended to provide guidance on the type of resources that should be considered and their priority of development."

A full analysis of all factors contributing to differences in the amounts of DSM[10] included in both planning documents has not been undertaken by the Company. Such an analysis would include detailed analysis of load growth assumptions, customer loads and density, CO2 cost assumptions, model differences, etc., and resource selection conventions specified in the Northwest Power Act in addition detailed analysis of the factors identified below. In this response, the Company has identified several factors that may contribute to differences in the DSM estimates and the likely impact (increase or decrease) of these factors.

Financial or structural planning assumptions affecting DSM

Valuation of DSM:

- The IRP selected DSM resources priced up to \$83/MWh for the entire planning period. In 2016 and beyond, some additional resources in the \$93- \$103/MWh bundle were also selected.
- The Power Plan utilizes a threshold of \$90/MWh for retrofits and \$120/MWh for lost opportunities.
- Likely Effect – Power Plan estimates are higher

Line loss assumptions:

- IRP modeling utilizes system line losses that reflect an average of actual losses by state for the 5-years ending December 31, 2007.
- The Power Plan stopped using the 7.625% regional average line losses utilized in the 5th Power Plan and incorporates line loss adders specific to load shapes. In general, line losses are higher in the Power Plan, compared to the 5th Power Plan.
- Likely Effect - higher line losses increase the selection of DSM as a resource. While differing line loss assumptions by state and load shape may contribute to differences in a planning period, this factor is likely not a major factor in differences in DSM between the two plans.

[10] DSM is a broad term and for the purposes of this response is intended to refer to energy efficiency. The terms "conservation" in the 6th plan and "Class 2 DSM" in the IRP are references to energy efficiency.

Discount rates:

- The IRP uses a 7.4% nominal discount rate and assumes a 1.9% inflation rate. The real discount rate for the IRP is 5.5%.
- The Power Plan uses 5% real discount rate.
- Likely Effect - a lower discount rate contributes to increased amount of DSM in the Power Plan by assigning a higher present value to the stream of future benefits delivered by DSM which is typically funded up-front with today's dollars.

Value of non-power system benefits:

- Benefits for DSM resources in the IRP are electric savings only. (O&M costs are added to capital costs for measures if third-party data existed during assessment work).
- The Power Plan adds non-power system benefits (such as water savings for washing machines) as a system benefit.
- Likely Effect – in isolation this difference does not change amounts selected based on measure cost. It does likely improve the overall performance of the selected portfolio in the Power Plan.

Oregon data used for resource inputs:

- For Oregon, information regarding available demand side resource potential was provided by the Energy Trust of Oregon using their *Energy Efficiency and Conservation Measure Resource Assessment* dated May 4, 2006. This assessment was for the 2007-2017 planning period. A proxy for potential for the period from 2018 to 2027 was developed at the company's request and was "safe sized" by the Trust to include only 2/3 of the retrofit opportunities of the first ten years and no emerging technology. This information adjusted for planning periods (i.e., add resources in 2028 equal resources in 2027) and was utilized for the Oregon supply curves in the current IRP.

  The Energy Trust has recently completed their *Energy Efficiency and Conservation Measure Resource Assessment for the years 2008 -2027* the final report is dated February 26, 2009. The extended planning period is consistent with legislative changes extending public purpose funding. This report includes an estimate of the distribution efficiency improvements. A high level comparison between the Power Plan and this assessment performed recently by a member of the Energy Trust's planning and evaluation department indicates similar amounts of cost-effective conservation resources.

New sources of savings:

Distribution efficiency

- IRP does not include this measure since the Company's assessment of potential resources pre-dated data with sufficient certainty for planning purposes.
- Power Plan - improved efficiency of the utility system is included as a measure. This measure was not included in prior Plans and is one of the larger factors in the Power Plan increase over the 5th Power Plan.
- Likely Effect – Power Plan estimates for this measure are higher.

Consumer electronics:

- IRP data is based on consumer electronic information available at the time which included only HDTV and digital set top receivers.

- Power Plan includes latest information on the rapidly changing consumer electronic market and includes potential from a broad list including all TVs, desktops computers and set top boxes.
- Likely Effect – Power Plan estimates for this measure are higher

Outdoor lighting:
- 6th plan includes increased opportunities from LED (lighting emitting diode) applications in outdoor lighting. Analysis takes advantage of current (and declining) cost estimates.
- Cost estimates for LED technology (beyond exit signs) in the IRP are above the cost for which resources were selected (and in some cases beyond the 6th plan thresholds).
- Likely Effect – higher potential for this measure in Power Plan.

Increased savings from technology improvements (including cost reductions)
Heat pump water heaters:
- The IRP supply curves costs for this measure are above the cost effectiveness thresholds and were not selected. (and would not have been selected using Power Plan thresholds).
- Power Plan has updated (lower) cost information and penetration assumptions for this measure, most of which assume eventual market traction resulting in ramp up in the out years of the plan.
- Likely Effect – Power Plan estimates for this measure are higher by including this measure (utilizing lower costs estimates).

High efficiency heat pumps:
- IRP supply curve costs for heat pumps were the best available at the time and are above the IRP cost effectiveness thresholds).
- Power Plan evaluates this measure with updated (reduced) measure costs expected to be realized within the planning horizon. .
- Likely Effect – Power Plan estimates for this measure are higher.

Increased savings from more detailed conservation assessment
- IRP supply curves utilized data from the Company's Assessment that estimated one-third of the industrial potential was delivered by behavioral or operations and maintenance practices.
- As a result of a more detailed conservation assessment, the Power Plan includes the effect of business management practices. Measures described as 'tune-up" or likely to be more heavily weighted toward behaviors than measures account for approximately two thirds of the savings.
- Likely Effect – Power Plan estimates are higher.

Decreases in savings estimates
Residential lighting – twister CFL:
- IRP includes potential from this measure.
- Power Plan removes twister CFL potential in anticipation of new federal standards.
- Likely Effect – IRP estimates are higher.

DSM planning is an iterative process and acquisition is not constrained

DSM planning is an iterative process for the utility, the states and region. Planning estimates are informed by the best available data on acquisition results, measure and delivery costs as well as parallel and complementary planning efforts. In a robust planning and delivery environment, it is unlikely that all schedules will coincide completely.

If the schedules had aligned, the Energy Trust and Power plan work would have helped inform the Company's current effort to update the potential study and generate new supply curves for the 2008 IRP. Since schedules did not align, it was necessary to utilize best available data which was the Company's potential study and the Energy Trust's 2006 potential study for the DSM estimates in the 2008 IRP. Updated information from the Energy Trust and the power plan will help inform the next iteration of the Company's potential study and the DSM estimates included in the next IRP.

Note that the preferred portfolio conservation targets in no way constrain acquisition of additional DSM, because the modeled results are based on a certain set of input assumptions made at the time the IRP was prepared. Furthermore, given the long-term aspects of conservation and how it's typically delivered, the Company would not constrain program activity to just meet its preferred portfolio if program performance is cost effective when compared to IRP generated decrement values.