



# State of Utah

## DEPARTMENT OF COMMERCE

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### Memorandum

To: Public Service Commission

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Date: March 31, 2003

RE: Docket 03-2035-01: *In the Matter of the Acknowledgment of PacifiCorp's Integrated Resource Plan 2003*

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#### I. SUBJECT

PacifiCorp, doing business in Utah as Utah Power & Light Company (Company), filed its seventh integrated resource plan (IRP) January 24, 2003 in response to the Utah Public Service Commission's (Commission) IRP Standards and Guidelines. The Commission issued its *Request For Comments* on January 31, 2003, asking for written comments on the adequacy of the Company's filing by March 10, 2003. This date was subsequently modified to March 31, 2003 to allow parties sufficient time to review and evaluate the document.

Subsequent to comment review, it is expected that the Commission will either establish a hearing schedule for further evidence and deliberation or issue an order. Acknowledgment of any IRP does not connote any pre-approval of resources acquired by the Company. Prudence determinations of resource acquisitions will be made during appropriate proceedings. This memorandum provides the Commission with the Division of Public Utilities (Division) comments on PacifiCorp's 2003 filed IRP. The Division appreciates the opportunity to provide these comments.

## II. RECOMMENDATION

The Division recommends acknowledgement of the IRP and we commend the Company's efforts to improve both IRP modeling and staffing of the IRP process. Our recommendation is based on the assessment that for the most part the contents of this IRP and the associated process of developing it comply with the Commission's Standards and Guidelines (Docket No. 90-2035-01). However, we have questions and concerns about some aspects of the report. To address these concerns we have developed a set of recommendations that fall into four areas: The Action Plan; DSM and Renewable Modeling Questions; Transmission Issues, and Future IRP Recommendations. In addition we make recommendations regarding the development of a local resource planning process that builds on this 2003 Integrated Resource Plan for the entire PacifiCorp system.

### ACTION PLAN

- The Company should provide annually updated Action Plans, as it has indicated it would do
- As part of PacifiCorp's update of its 2003 Action Plan, the Company should identify what risk benefits may have been associated with Diversified Portfolio I compared to the base-case portfolio with regards to CO2 scenarios, gas prices, and cost recovery uncertainty amelioration from delaying the largest single portfolio investment

### DSM AND RENEWABLES MODELING RECOMMENDATIONS

- The Company should provide as soon as feasible a more complete description of the DSM analysis utilized in this IRP, providing increased detail on both the theory and the calculations of costs and savings
- Attention should be given to assuring that the IRP's cost-effectiveness criterion is compatible with all the Utah Commission's DSM standards to assure that DSM modeled can be implemented
- A review of DSM that the Company considers it can cost effectively implement (i.e., programs that would pass the tests required by the PSC for cost recovery) should be provided no later than in its annually updated Action Plan.
- The Company should provide an assessment of the potential impacts on peak load consumption associated with the different amounts and types (i.e., load shapes) of Class 2 DSM measures
- The wind integration methodology and results need to be further explained and additional analytic support provided

### TRANSMISSION ISSUES

- The Company should continue to provide clarity around transmission assumptions and opportunities to assure that transmission opportunities are

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fully evaluated and that supply side generation decisions are based on the known and measurable constraints on the system

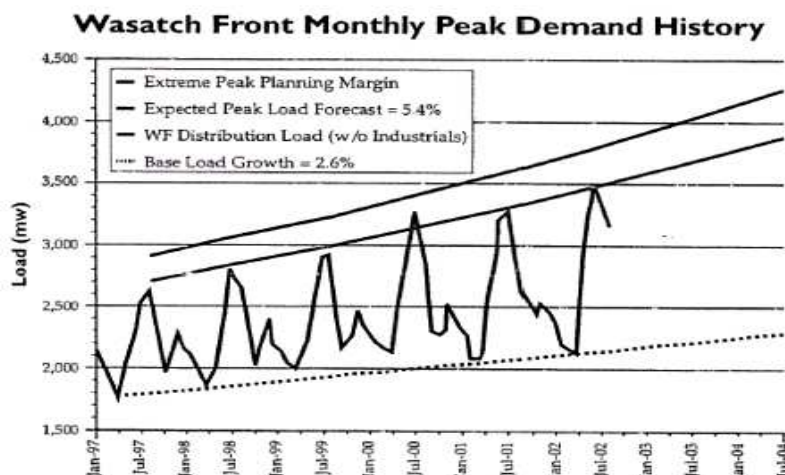
- Non-firm transmission rights should be included in the modeling and results – not to affect the capacity to meet peak demands, but to potentially alter the portfolio mix insofar as more off-system surplus sales opportunities would be manifest
- The transmission-oriented portfolios should be re-evaluated based upon the latest RTO-WEST thinking regarding having all transmission beneficiaries, rather than merely the direct contractual participants, contribute to cost recovery

### RECOMMENDATIONS FOR NEXT IRP

- The Company should convene as soon as feasible a public input meeting to assess modeling concerns going forward that would include the use of optimization logic in future IRPs
- Additional clarification regarding the utilized risk analysis should be provided
- Docket No. 02-035-03 *In the Matter of the Reexamination of Integrated Resource Planning (IRP) and the Guidelines According to Which it Should Occur* be reopened to examine IRP “process” issues

### RECOMMENDATION FOR A LOCAL IRP

The Division is particularly concerned that the Company forecasts that peak demand in the East will increase at double the rate of average load growth. In addition, the IRP has identified that PacifiCorp East has transmission limitations creating difficulties getting power into particularly high growth areas in Utah. In Utah Power’s “Voices” insert in March customer bills included the following graph



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The graph represents the historical load as well as what the Company estimates for loads along the Wasatch Front. The Company expects base load growth to be 2.6% but its expected peak load forecast is 5.4%. We have estimated what impact it would have on capacity needs if peak grew at about the same level as base load. (We do not have the numbers behind this graph therefore we must estimate.) It appears that this graph is demonstrating that, at peak in 2002, the Wasatch Front demand was about 3500 MW. If peak demand grows at the anticipated 5.4%, demand will be about 3888 MW by 2004 compared to 3684 MW if peak grew at 2.6%, the same as base load. This is a difference of about 200 MW. The amount of capacity needed for what is termed "Extreme Peak Planning Margin" adds to the problem. The extreme peakiness of the Wasatch Front load adds to the problem. According to the graph, in 2002 there was a difference of about 1400 MW between base load and peak demand further demonstrating how critical it is to manage peak growth in Utah.

In short, the Division does not accept that the rate of peak load growth is a given. The Division believes that significant reductions in peak growth can be secured through effective implementation of demand side and other measures that could significantly change the type of resources needed if peak growth were effectively managed to be more aligned with average growth.

Therefore, the Division recommends the development of a local resource planning process that builds on this 2003 Integrated Resource Plan to begin in the second quarter of 2003. Such a process would include evaluation of distribution investment, demand side alternatives, rate design, combined heat and power, and distributed generation, along with supply and transmission investments as modeled in this current IRP. Based on the outcome of the local planning process, PacifiCorp will need to refine its estimates of peak load growth going forward as measures are implemented leading to manage peak demand, especially within the Utah jurisdiction

A more complete discussion of these recommendations and the basis for each is provided below.

### **III. STANDARDS AND GUIDELINES**

Based on Division review of the IRP and also staff participation in public meetings, the assessment is that PacifiCorp has made a strong and concerted effort to comply with the Commission's Standards and Guidelines. In many respects, the filed IRP meets the required standards and guidelines. However, the Division is concerned that elements of this IRP are not consistent with the all of the applicable principles contained in the currently mandated standards and guidelines. The following addresses to what extent the 2003 IRP comports with the current standards and guidelines and identifies those areas where the Division believes this IRP is inconsistent with those principles.

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### *Filing Requirement and Frequency*

PacifiCorp's seventh IRP was due December 31, 2002. However, based on comments received in the public input process on its draft report, PacifiCorp chose to make use of a short delay in order to better develop key areas of the final report. The participants in the process supported this delay.<sup>1</sup> The Division supported this delay, noting that use of the additional time to resolve problems would likely lead to a improved documentation of the resource plan.

PacifiCorp filed its 2003 IRP January 24, 2003. Thus, the Division considers that the Company did file its seventh IRP in a timely manner, meeting the filing requirement and the biennial target, as consistent with the Commission's Standards and Guidelines.

### *Process*

PacifiCorp held ten public input meetings over the past year. However, there were requests made during these meetings to which the Company could not provide a public response. In particular, certain detailed data regarding loads and resources and transmission capacity were deemed highly sensitive. Thus, delivery of the data was highly restricted. While the Division understands the need for caution and appreciates the sensitivity of this data, we also recognize that the increasingly confidential nature of data limits the public input process. It is the Division's assessment that the Company has made a strong effort to maintain the integrity of the public process consistent with the mandated Standards and Guidelines, but the nature of certain data has restricted full public involvement. We, therefore, recommend that the Commission reopen Docket 01-035-03 *In the Matter of the Reexamination of Integrated Resource Planning (IRP) and the Guidelines According to Which it Should Occur* to examine IRP "process" issues, with emphasis on balancing the public input process with PacifiCorp's need for confidentiality

### *Focus*

The Standards and Guidelines require that the filed IRP include a 20-year planning horizon along with a short-term action plan. The analysis contained in the IRP is for 20-years and specific action items for the short term are identified in Chapter 9 of the report, which is entitled "Action Plan."

The plan identifies the resources that PacifiCorp concludes ought to be pursued based on its analysis that these are consistent with a least-cost, low-risk portfolio, *Diversified Portfolio I* (DPI). Over the ten year period 2004-2014 (fiscal years), the following resources are identified as cost-effective (DPI):

<sup>1</sup> The Division is not aware of any party expressing concern over the delay.

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- 1400 MW Renewables
- 1200 MW Peakers
- 2100 MW Base load
- 450 MWa DSM and 91 MW Direct Load Control
- 700 MW Shaped Products

The near term action required to guide the Company in procurement of these resources, but also to promote flexibility as conditions change, are listed in table 9.1 on page 153 of the report. The table identifies the public process requirements going forward, as well as the specific actions PacifiCorp must take to meet its near term goals. A target delivery date is specified for each action. Dates span the period January 2003 to July 2004. This term is slightly shorter than the two year requirement for specific actions required under the mandated Standards and Guidelines. However, the Company plans now to deliver annual Updated Action Plans to more closely match the actual business strategies pursued by the Company. Additionally, the Action Plan does identify resource requirements over the next four years (Peakers in 2006, Base Load in 2007 and 2008, Shaped Products 2004-2007, and DSM) along with the immediate actions needed to meet those resource goals and the associated decision process.

The Division supports the transition to annually updated Action Plans and recommends that it be implemented as a requirement for the IRP process. As this may be inconsistent with the current Standards and Guidelines, the Division recommends that Docket 02-035-03 be reopened to address this issue.

#### *Least Cost Portfolio Analysis*

PacifiCorp analyzed four major categories of portfolios:(1) Thermal, containing four different subcategories; (2) Alternative Technology, with two subcategories; (3) Transmission as a subset of the thermal portfolios and containing two categories; and (4) Hybrid portfolios, containing five portfolios.<sup>2</sup> The selection of portfolios was based on a preliminary iterative process utilized to narrow down the number to only those deemed to be in the realm of optimality. The criteria upon which this assessment was based is contained in Appendix J of the IRP. Final portfolios were assessed to determine which one generated the lowest present value revenue requirement (PVRR) coupled with the least amount of risk (as categorized by PacifiCorp).

Most of the final portfolios considered seemed to have more elements that were common (or nearly common) than disparate.<sup>3</sup> Accordingly, it is not surprising that their

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<sup>2</sup> Chapter 6 pages 81-86.

<sup>3</sup> For example, the only difference between Diversified Portfolio I and Coal/Gas III was that the former added 624 MWs of wind power. Those additions did not affect the timing of any of the thermal additions or contracts.

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twenty-year estimated PVRRs are very similar. While not intended to be a direct criticism of the IRP portfolio selection per se, it does bring into question the degree to which an “optimum” portfolio determination can be made utilizing the PacifiCorp method; i.e., by making various perturbations in the neighborhood of that requirement- and constraint-driven optimum. In this case, the “neighborhood” had a lot of intuitive appeal – employing a “diverse” blend of technologies and fuels. The portfolio perturbations altered the time of when the various resources came on board and made more or less minor substitutions of wind, for example, for thermal technologies. Aside from the caveats mentioned below, it is difficult to imagine what kind of supplemental evidence would lead to the conclusion that the PacifiCorp-preferred portfolio (i.e., DP1) was in any major way inappropriate.

Appropriately, the IRP Action Plan incorporates a lot of flexibility. For example, given a major change in wind subsidies or emission taxes, the preferred portfolio can, to various degrees depending upon the timing of the new information, be altered to reflect those changes. One variation, identified as Variation 2 (Table 7.11, page 134) of the base-case (DP1) portfolio was to place the expensive, new Hunter 4 plant at the end of the line (in 2012), after the Gadsby CCCT re-power and the Mona CCCT, rather than at the beginning of that construction queue (i.e., in 2008). The PVRR penalty of that variation was minuscule (0.03%). The IRP text indicated the advantage of that variation in terms of “emissions reductions.” The Company did not clearly identify what risk benefits may have been associated with the alternative variation compared to the base-case portfolio with regards to CO2 scenarios, gas prices, and cost recovery uncertainty amelioration from delaying the largest single portfolio investment. Thus, the Division recommends that, as part of its update of its 2003 Action Plan, such an analysis be performed, or if it has been performed, that such results be submitted for review.

In general, it is difficult to state that the IRP satisfies the goal (standard) of “least cost.” However, it may be that this goal conflicts with other goals such as, taking into account environmental impacts/risks, and evaluating supply and demand side resources on an equal footing. Additionally, taking these factors into consideration is in the Division’s estimation consistent with the Commission’s Standards and Guidelines.

The issues, however, of least cost planning is not resolved by the above-mentioned concession, as the IRP model lacks optimizing logic. Thus, it cannot be demonstrably shown that the IRP reflects least cost in the traditional (i.e., historical) sense. With that noted, the IRP may be a reasonable compromise in fulfilling what may be conflicting or incompatible standards.

Another matter of concern, given the fact that the various portfolios will differ in the timing by which their resource additions occur, is whether or not the portfolios’ analytic rankings might be affected by the way that the time-value discounting and fixed-cost leveling was performed. This concern was basically eliminated in the IRP’s wherein

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two valuable alternative analyses were performed. (They are shown in Table E.17, on page 298 of the IRP.) In one case nominal annual revenue requirements were substituted for real, i.e., inflation-adjusted, levelized annual revenue requirements; in the other case an annual discount rate of 2.5% (i.e., the expected rate of inflation) was substituted for the rate equaling the Company's after-tax real cost of capital, 7.5%. While those substitutions did slightly alter the PVRR rankings of some of the portfolios, it did not displace the "Diversified Portfolio I" as the portfolio with the lowest PVRR.

### *Evaluation of Resources*

The Standards and Guidelines require that PacifiCorp evaluate all resources (Demand- and Supply-Side) on a consistent and comparable basis. In Chapter 5 of the 2003 IRP, PacifiCorp outlined resource alternatives. Additionally, all portfolios evaluated contained a combination of demand-side and supply-side options, including renewables. The Division commends the Company on its efforts to more progressively evaluate both renewables and also demand side options. However, it is not clear that the evaluations are "comparable" across all options. On this issue the Division has three primary concerns:

- 1) Does the IRP adequately evaluate opportunities for enhancement to the transmission system or is it unduly constrained by the paradigmatic risk associate with RTO development?
- 2) Are DSM options comparably evaluated compared to supply side options in terms of the benefits provided to the system (i.e., local benefits to the distribution system)?
- 3) Are renewables, primarily wind resources, comparably evaluated given the limiting assumptions for wind resources in the modeling process?

Exploration of transmission assumptions utilized in the IRP is an ongoing effort between regulators and the Company. We recommend that the Company continue to provide clarity around this issue to assure that transmission opportunities are fully evaluated and that supply side generation decisions are based on the known and measurable constraints on the system. For example, on page 76 of the report it is stated that "the main area of congestion on the (transmission) system is Utah...simultaneous import capability into the Utah bubble is significantly lower that the sum of the non-simultaneous path limits..." Support for this assertion cannot be clearly identified in the text of the IRP. It is also not clear whether or not "fixes" to this problem have been adequately explored.

Regarding DSM, we recommend that the Company continue to develop and enhance DSM modeling and that as new Class 2 DSM measures are pursued the impacts on average load growth, peak load growth, and supply side decisions be evaluated in the context of the IRP updated Action Plan. Further discussion of DSM issues is contained

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in the “DSM” section to this memo, which is provided below.

The issue of how to properly evaluate wind resources was explored in great detail during the public input process. Ultimately, PacifiCorp assessed that the total wind resource cost was the sum of capital cost, O&M cost, transmission cost, and integration cost less the production tax credit and renewable energy credit.<sup>4</sup> The Division believes that this is a reasonable approach. However, the fact that the PROSYM dispatch model assumes a foreknowledge of wind generation in its unit commitment logic makes the problem deterministic when the risk is really stochastic. This will result in a point estimate rather than an interval estimate giving a range of outcomes. This makes it hard for one to quantify the true impact that this assumption has on the imbalance cost. It could be argued that modeling wind generation deterministically will result in underestimation of the imbalance cost. If so, then the extent of underestimation needs to be quantified and compared with the suspected overestimation resulting from the PROSYM’s assumption of Hydro dispatch without consideration of wind generation. This will indicate the combined effect of these two assumptions. If the combined effect is an underestimation of the imbalance cost, it will make the wind resources appear to be more cost effective than it is. The opposite is true if the combined effect is an overestimation of the imbalance cost. Therefore, it is unclear whether the IRP is bringing in more, less, or adequate amounts of wind energy into the final portfolio. Therefore it appears that the PROSYM dispatch model is not the appropriate model for wind generation for it cannot handle stochastic wind generation model.

In sum, the Division recommends that the Company provide an enhanced analytic evaluation of its modeling of wind resources. It is also the Division’s recommendation that the PacifiCorp explain why the wind resource cost assumptions listed at the bottom of page 370 and the wind resource costs in Table L.1 on page 371 do not match the numbers on Tables C.19 and C.20 on pages 213 and 214.

#### *Uncertainty and Risk and Risk Allocation*

In general, the outcome of a future event is unknown. If the researcher can assign probabilities to the possible outcomes in a reasonable manner, then technically, the event is defined as being “risky.” If the researcher, for one reason or another – for example a lack of historical data or experience – feels that probabilities cannot be assigned to the set of outcomes, then the event is defined as being “uncertain.” PacifiCorp defines risk according to three basic categories: Stochastic, Scenario, and Paradigm. Of these three classifications, as PacifiCorp explains, only the first – Stochastic Risk – can be analyzed using known statistical models/processes and is, therefore, technically a risky event. The other two classifications are “uncertain” events and are modeled using “what if” techniques. A more thorough overview of the risk modeling process is contained in

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<sup>4</sup> The integration cost is defined as the sum of the imbalance cost and the incremental operating reserve cost.

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Attachment A to this memo. This classification appears consistent with the standards and guidelines. It is also the Division's assessment that PacifiCorp utilizes a reasonable approach to analyzing portfolios given the classification of risks in chapter 3. Although we recommend that the Company examine the potential of using optimization logic in its modeling, the current approach appears to be reasonably consistent with the standards and guidelines.<sup>5</sup> However, we recommend that additional clarification regarding the utilized risk analysis be provided based on the discussion contained in Attachment A to this memo.

There are two types of analyses in this area that the 90-2035-01 Guidelines seemed to call for but were not given explicit treatment in the IRP document. One was some indication of how the risk burdens would be distributed between shareholders and ratepayers. The second consideration was the manner by which scenario and paradigm risks might lead to a "course correction" in the form of a portfolio change. . It would also be valuable if the IRP provided an indication of the degree of adversity that would cause a change in the portfolio makeup to answer the question as to what change(s) in the projected environment would lead PacifiCorp to depart from its favored Diversified Portfolio I. That would have aided the evaluation of the need for flexibility in the Action Plan by providing some indication of what it would take to force the Company to abandon one investment path and replace it with another. It is our expectation that the next edition of the IRP will address these two matters.

#### *Strategic Business Plan*

It is the Division's estimation that the IRP is consistent with the Company's strategic business plan. The IRP has identified a clear need for new resources going forward, with some need to fill the present gap between loads and resources. The Action Plan identifies steps that PacifiCorp will take in the short-term in an effort to procure additional amounts of DSM and obtain through contracts shaped products to meet its immediate resource needs. Since it could be assessed that it would be imprudent for the Company to either not seek to secure resources for its short-term needs or those required for longer-term balance, it seems reasonable to conclude that the PacifiCorp will pursue these options to insulate itself from both regulatory risk and market risk.

#### *External Costs*

It is the Division's estimation that the Company has made a concerted effort to adequately model external costs and that the modeling effort is consistent with the Standards and Guidelines. We do, however, have concerns about carbon tax modeling in

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<sup>5</sup>The basic model is a two-factor lognormal mean-reversion model. The two factors are the short and long run variables such as prices and loads. Variables are assumed to follow a lognormal distribution, which is consistent with financial/economic data modeling. Short-run shocks in the model tend to revert to the long-run trend, which is consistent with the random-walk hypothesis.

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the determination of the optimal portfolio. This is discussed in further detail under “Least Cost Planning.”

### *Competitive Bidding*

The IRP is consistent with the Standards and Guidelines in its assessment of competitive bids as an option to building new supply side resources. While the base case portfolio, DPI, assumes that in the long-run PacifiCorp will build resources, numerous references in the IRP stress that prior to building competitive bid options will be explored. Thus, the implied assumption is the PacifiCorp will contract for resources subsequent to a competitive bidding process in those instances where the bid results in a cost less than that of the preferred portfolio (DPI).

The IRP also indicates that a competitive bidding process is presently being used or has been used to secure resources through 2005. A description of this strategy is contained on page 161 of the report. Docket number 03-035-03 has been opened to examine PacifiCorp’s competitive bidding process.

### *Resource Acquisition Paths*

Resource Acquisition paths are largely dependent on assumptions that are input into the model. A key assumption is that which is made with respect to load growth. PacifiCorp’s load growth assumptions are contained in Appendix K of the report. Division staff reviewed this appendix in November 2002 after the Company provided its draft IRP and submitted written comments with specific issues. The primary issue was that PacifiCorp indicated using multiple regression and econometric models to forecast the load for the different customer classes but did not provide equations for these models, nor did they provide a detailed description of these models. These issues pertained to the particular multiple regression and econometric models used to forecast the load for the different customer classes. PacifiCorp has dealt with these issues to the DPU’s satisfaction. They included in the final IRP a detailed description of the models used along with the relevant equations. Hence the Division of Public Utilities would recommend the Public Service Commission to acknowledge the retail load forecasts models.

However, the Division does not accept that the rate of peak load growth is a given. The Division believes that significant reductions in peak growth can be secured through effective implementation of DSM and other measures that we expect could be discovered in a local resource planning process that could significantly change the type of resources needed if peak growth were more aligned with average growth. We believe that PacifiCorp will need to refine its estimates of peak load growth going forward as DSM measures are implemented leading to reduced peak demand, especially within the Utah jurisdiction.

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### *Cost Effectiveness*

The Standards and Guidelines require that the cost-effectiveness of all resource options be explored. The Division considers that the Company has included in its list of “candidate” resources all resources which it could reasonable be expected to pursue (Chapter 5). However, we do have some concerns about the cost effectiveness test applied to the various resources. In particular, the standards and guidelines require the use of the Total Resource Cost tests. The use and application of this test is unclear with respect to renewables and DSM. These issues are discussed in further detail below under “DSM” and above under “Evaluation of Resources.”

### *Progress Report on RAMPP-6*

The Division assesses that the Company has made significant improvements in the IRP process and report. The Company addressed many of the issues raised in RAMPP-6 comments and orders. Two areas where additional work is needed are in terms of distributed generation and DSM evaluation. In particular, PacifiCorp has not addressed in an analytically thorough manner the potential impacts of either distributed generation or DSM on the local distribution system. We believe this needs to be done in order for the Company to have met its objectives as stated in its Updated RAMPP-6 Action Plan and also to be in compliance with the Commission orders (RAMPP-6 Orders and Standards and Guidelines). A more detailed discussion is provided in the “RAMPP-6” review contained in Attachment C to this memo.

### *DSM*

PacifiCorp has adopted a new methodology for evaluation of many its demand side options. First, DSM measures that are dispatchable, i.e., directly under Company control, are modeled similar to supply side resources. However, there are DSM measures that are not considered dispatchable but offer a significant and clear opportunity for load reduction. These measures are referred to as DSM “conservation” programs (referred to as Class 2 DSM in the IRP). Class 2 measures are modeled as decrements to the load forecast. The approach is referred to as the “decrement” method, because it evaluates demand side options as decrements to the load.

The logic behind the decrement approach is relatively simple; since DSM measures are designed to reduce load, it seems reasonable to evaluate DSM as a reduction in load over time as the measure is implemented and impacts demand. The application of the method is more complex. First, it was determined that some “base” amount of DSM would be included in all portfolios. Utilizing the levelized costs of existing DSM measures and specific planned measures, PacifiCorp made a decision to incorporate all DSM measures with levelized costs of \$39/MWH or less. This cutoff

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point led to the determination that about 146 MW (rounded to 150 MW in some areas of the report) of Class 2 DSM was cost effective and should be included in all portfolios.<sup>6</sup> This was done by decrementing the “base load forecast” in all IRP portfolios.<sup>7</sup>

The next step was to identify additional amounts of DSM that could be cost effectively procured. To assess this, the Company evaluated different types of DSM measures within the Class 2 category, each with different associated load shapes. Next, each DSM measure was evaluated separately as compared to a defined base portfolio (DPI). In other words, each program is considered to lead to a specific load reduction. The IRP is run with a specific program reduction. The new run is compared (subtracted) from the base run (DPI) to determine a value for each program. In addition, the implications for supply side resource planning are captured. The result is a \$/MWh for each program measure.<sup>8</sup> The decrement values derived from this approach will be used to evaluate new DSM programs.<sup>9</sup> Based on this analysis, the Company believes that it can cost effectively procure an additional 300 MWa of Class 2 DSM, for a total of 450 MWa.

In sum, the decrement method utilizes a hard input method to model DSM; i.e., it is not an output of the model. Thus, it is not possible to identify the “optimal” level of DSM. However, the Division does commend the Company on both its efforts to more effectively model DSM and also its recognition of the need for more progressive and aggressive DSM measures. The concern is that DSM measures are subjectively evaluated based on an avoided cost cut-off measure. As the IRP process develops, it is our recommendation that more objective evaluation methods be developed in order to assure that all cost effective measures to reduce Utah’s substantial peak load growth are evaluated and pursued where warranted.

To this end, we recommend the development of a local resource planning process to begin in the second quarter of 2003. Such a process would include evaluation of distribution investment, demand side alternatives, rate design, combined heat and power, and distributed generation along with supply and transmission investments as modeled in this current IRP. The local IRP would look at “Portfolio Category: Alternative Technology” that is not currently in the plan and includes 30MW of new A/C load control; and, the possible additional Class 1 & 3 DSM 50-100 MW as identified on page 146 of the IRP. We believe this idea fits in with two of PacifiCorp’s stated action plan items:

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<sup>6</sup> It is assumed that the peak reduction would be substantially higher depending on the program associated load factor.

<sup>7</sup> This amount is in addition to the base amount of Class 1 DSM, which is assumed to be 91 MW based on the Utah AC load control program for residential and small commercial customers.

<sup>8</sup> The \$/MWh savings is calculated as the [(base load revenue requirement - decrement case revenue requirement)/Total MWh savings =  $\Delta$ Revenue Requirement/MWh reduction.

<sup>9</sup> Essentially, the decrement values are being used as a proxy for “avoided costs.”

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1. "Conduct an Economic and Market Potential study of the PPW Service territory to determine the magnitude of the DSM opportunities available to PacifiCorp" -- Target delivery date August 2003
2. Design a "bundle" of cost effective DSM programs that build to an additional 300 MWa between 2004 and 2014 in line with the decrement options reviewed in the IRP" -- Target delivery date July 2003

We believe that it is important that PacifiCorp (and others) investigate aggressive and ongoing solutions to reducing peak demand in the future, as this allows for resource diversity, leads to acquisition of demand side resources that are more analogous to supply side options, and alleviates rate pressure deriving from high peak growth in Utah.

Prospective DSM programs must pass through a cost-effectiveness screening to be approved for cost recovery by the Utah Commission. PacifiCorp has stated in its IRP that it intends to pursue all cost-effective DSM. The explicit test proposed in the IRP is the following "If the cost of running the DSM programs in a particular decrement is less than the decrement value, then they are cost effective to the PacifiCorp system." The "decrement value" in this context is the reduction in the PVRR -- exclusive of DSM program costs -- associated with the decrement or reduction in load consequent to the DSM program. This cost effectiveness test appears to be overly permissive, which could result in modeling for DSM that would not be implemented since it would not be approved in Utah for cost recovery. Conversely, the first-stage IRP requirements that DSM program costs be less than \$30 per avoided MWh seems to be overly restrictive. Part of carrying out Implementation Action #13 (Determine revised DSM targets for the period 2004 to 2014...October, 2003), must be a resolution of this cost-effectiveness issue.

It is not clear what test the IRP uses to include DSM measures into its plan. Therefore the Division makes the following recommendation. The Company should provide as soon as feasible a more complete description of the DSM analysis utilized in this IRP, providing increased detail on both the theory and the calculations of costs and savings. Attention should be given to assuring that the IRP's cost-effectiveness criterion is compatible with all the Utah Commission's DSM standards to assure that DSM modeled can be implemented. For the future, the Division also recommends that PacifiCorp review the DSM that the Company considers it can cost effectively implement (i.e., programs that would pass the tests required by the PSC for cost recovery) in its annually updated Action Plan. Attachment B provides a more complete discussion of this issue.

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#### IV. CONCLUDING REMARKS

The Division believes that PacifiCorp has made positive efforts to improve its IRP process, with the result that its 2003 IRP is a significant improvement in many respects over its past two reports (RAMPP-5 and RAMPP-6). Critical aspects of the current IRP, though, are new and additional efforts are required to improve the robustness of the analysis.

In its Order in Docket 98-2035-05, the Commission stated that:

It is apparent that in some instances the Company has either ignored or downplayed requests of the parties and the Commission for adequate analysis of scenarios, risk, and demand-side management opportunities. This cannot continue. (Docket No. 98-2035-05, Order issued February 23, 2002, pg 9).

The Division believes, as discussed in detail above, that PacifiCorp has responded to these concerns and has made concerted efforts to improve DSM analysis, risk assessment and scenario testing.

The Division recommendation for acknowledgement of this IRP rests on two primary assessments: (1) The Company has made significant improvements in the IRP process and modeling and (2) The Action Plan follows reasonably from the assumptions contained in the report. We are also satisfied that the IRP is a good reflection of the Company's business plan going forward. The Company has stated that its goal is to have a "flexible" resource plan that allows for efficient decision making under changing circumstances. We believe this to be consistent with its stated intent to focus on its regulatory business to assure that loads are met in the most cost effective manner.

Although we have some concerns regarding this report, it is the Division's intent that this process continues to move forward both in terms of more rigorous modeling and clarified assumptions. To this end, the Division has made a number of recommendations. Additionally, the Division has identified aspects of the report that are either inconsistent with the current Standards and Guidelines, or appear inconsistent requiring that the Company provide clarification. Two issues that appear on the face to be inconsistent are: (1) Increasing use of confidential data, which makes the process less than public and (2) this plan is not an "optimal;" i.e., least-cost, plan as defined historically. While it is not the Division's contention that either should result in non-acknowledgement of the report, both seem to lead to the need for reexamination of the standards and guidelines. A third, which is more problematic for the Division, has to do with the comparable assessment of resource alternatives. In particular, it is not clear that all resources alternatives were comparably compared; i.e., that transmission, renewables, and DSM were compared on a

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basis comparable to all other supply-side resources. To address this Division recommends that the Company provide written clarification on the comparability of resource comparisons within 30 days of the Commission's order in this docket.

Cc: Janet Morrison, PacifiCorp  
Committee of Consumer Services  
Utah Energy Office  
Land and Water Fund of the Rockies  
Utah Association of Energy Users  
Ted Boyer, Director Department of Commerce

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