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# **Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans**

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# Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans

*Markets for renewable energy have historically been motivated by policy efforts, but a less widely recognized driver is poised to also play a major role in the coming years: utility integrated resource planning.*

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## I. Introduction

Markets for renewable electricity have grown significantly in recent years, motivated in part by federal tax incentives and in part by state renewables portfolio standards and renewable energy funds. State renewables portfolio standards, for example, motivated approximately 45% of the 4,300 MW of wind power installed in the U.S. from 2001 through 2004, while renewable energy funds supported an additional 15% of these installations.

Despite the importance of these state policies, a less widely recognized driver for renewable energy market growth is poised to also play an important role in the coming years: utility integrated resource planning (IRP). Formal resource planning processes have re-emerged in recent years as an important tool for utilities and regulators, particularly in regions where retail competition has failed to take root.<sup>1</sup>

In the western United States, recent resource plans contemplate a significant amount of renewable energy additions. These planned additions – primarily coming from wind power – are motivated by the improved economics of wind power, a growing acceptance of wind by electric utilities, and an increasing recognition of the inherent risks (e.g., natural gas price risk, environmental compliance risk) in fossil-based generation portfolios.

The treatment of renewable energy in utility resource plans is not uniform, however. Assumptions about the direct and indirect costs of renewable resources, as well as resource availability, differ, as do approaches to incorporating such resources into the candidate portfolios that are analyzed in utility IRPs. The treatment of natural gas price risk, as well as the risk of future environmental regulations, also varies substantially. How utilities balance expected

portfolio cost versus risk in selecting a preferred portfolio also differs. Each of these variables may have a substantial effect on the degree to which renewable energy contributes to the preferred portfolio of each utility IRP.

This article, which is based on a longer report from Berkeley Lab,<sup>2</sup> examines how twelve western utilities – Avista, Idaho Power, NorthWestern Energy (NorthWestern or NWE), Portland General Electric (PGE), Puget Sound Energy (PSE), PacifiCorp, Public Service Company of Colorado (PSCo), Nevada Power, Sierra Pacific, Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) – treat renewable energy in their recent resource plans. In aggregate, these utilities supply approximately half of all electricity demand in the western United States.

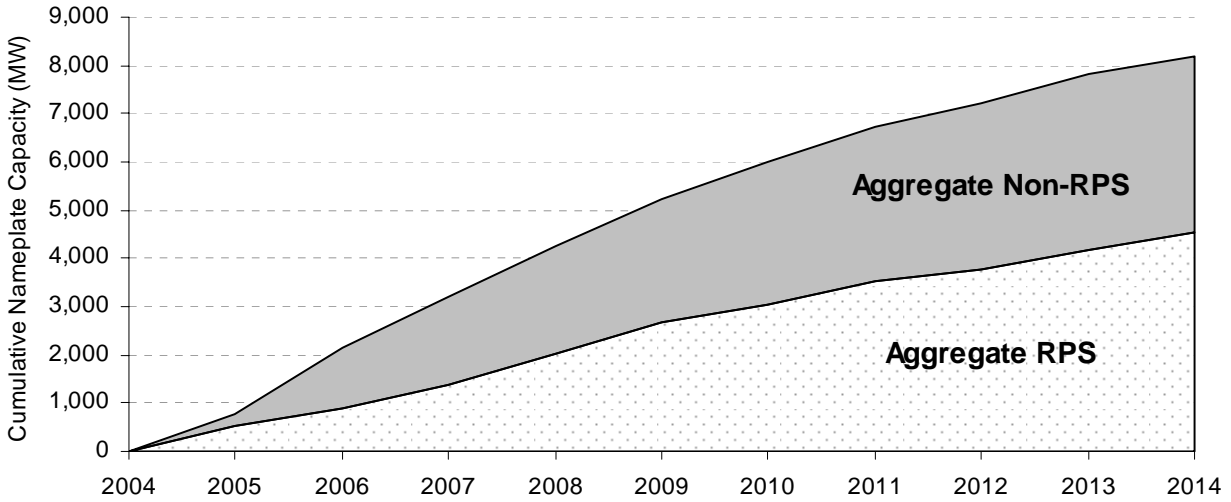
In reviewing these plans, our purpose is twofold: (1) to highlight the growing importance of utility IRP as a current and future driver of renewable energy, and (2) to suggest possible improvements to methods used to evaluate renewable energy as a resource option.<sup>3</sup>

This article begins with a discussion of the planned renewable energy additions called for by the twelve utilities in our sample, followed by an overview of how these plans incorporated renewables into candidate portfolios, and a review of the specific technology cost and performance assumptions they made, primarily for wind power. We then turn to the utilities' analysis of natural gas price and environmental compliance risks, and examine how the utilities traded off portfolio cost and risk in selecting a preferred portfolio.<sup>4</sup>

## **II. Planned Renewable Energy Additions**

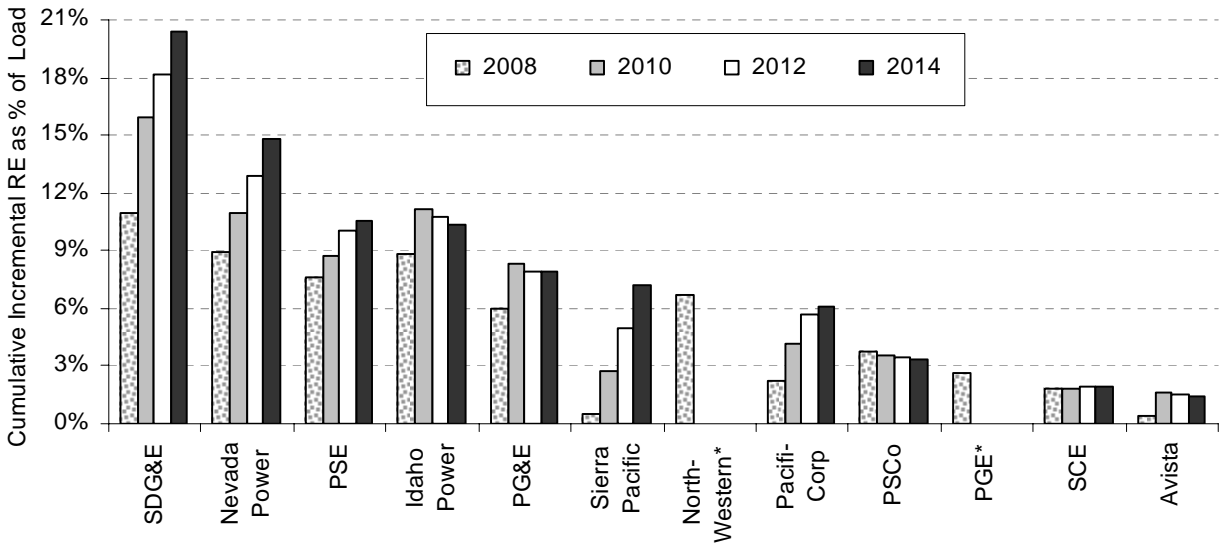
Recent western resource plans include a significant amount of planned renewable resource additions. In the case of the three California and two Nevada investor-owned utilities (IOUs) covered in this study, these additions are primarily the result of state-imposed renewables portfolio standards (RPS). The seven remaining utilities in our sample, however, are not subject to an RPS (or at least were not at the time of their most recent IRP filings – PSCo and NorthWestern have since become subject to an RPS), and plan to add renewables based solely on their own merits, as revealed through analysis of the expected cost, value, and risk mitigation benefits of renewable resources.

Figure 1 shows the cumulative, planned additions of renewable generating capacity among the twelve utilities in our sample, categorized as either RPS- or IRP-driven additions. As shown, the ~8,000 MW of new renewable capacity expected by 2014 is split almost evenly between each category.



**Figure 1. Planned Renewable Resource Additions in Twelve Western Resource Plans**

Figure 2 breaks out the cumulative planned renewable additions from Figure 1 by utility, and normalizes them as a percentage of projected utility load. Perhaps the most interesting observation is that two of the four most aggressive utilities by this metric *are not* subject to an RPS. Though RPS-driven planned additions might be considered *more certain* than non-RPS plans, Figures 1 and 2 clearly illustrate that non-RPS resource plans may themselves be a major driver of growth in new renewables. Wind power dominates these non-RPS planned additions: in aggregate, IRP-driven planned additions include 3,380 MW of wind power and 270 MW of other renewable resources.



**Figure 2. Cumulative Incremental Renewable GWh as a Percentage of Utility Load**

\*PGE's and NorthWestern's procurement horizons end in 2007, so only their 2008 values are shown.

Whether and to what degree these planned renewable additions – especially when not motivated by an RPS mandate – are subsequently achieved is an important avenue of future study. In nearly all cases, the utilities whose resource plans we reviewed are *beginning* to make good on

their plans to procure renewables, by issuing renewable energy solicitations and signing contracts with renewable generators. Despite these early efforts, however, an emerging disconnect between resource plans and procurement reality is also evident in some instances. A recent increase in wind project costs – driven by a combination of weakness in the US dollar, rising steel costs, turbine shortages, and the general rush to install projects before the then-scheduled expiration of the PTC at the end of 2005 – is perhaps partly to blame. But this disconnect also demonstrates the challenge of translating resource plans into actual renewable procurements, and the relatively higher uncertainty surrounding IRP-driven renewable energy additions, relative to RPS-driven additions.

### **III. Portfolio Construction**

Though the content of any specific utility IRP is unique, all are built on a common basic framework: development of peak demand and load forecasts, assessment of how these forecasts compare to existing and committed generation resources, identification and characterization of various resource options and candidate portfolios to fill a forecasted resource need, analysis of different candidate portfolios under base-case and alternative future scenarios, and selection of a preferred portfolio and creation of a near-term action plan.

Our review of twelve western resource plans reveals that, in most cases, candidate resource portfolios are constructed by hand, featuring resources that are regionally available and that passed initial cost or performance screening tests (the two exceptions to handcrafted scenarios are PSCo and Avista, both of which use optimization procedures). Though this “pre-selection” of candidate portfolios may simplify the modeling process – an important consideration, to be sure – it also allows human bias to influence the outcome, by limiting the universe from which the optimal portfolio emerges. If renewable resources are not accurately or adequately represented within the candidate portfolios, or if a broad range of candidate portfolios is not considered, the modeling outcome could be sub-optimal.<sup>5</sup>

Within this context, we note with some concern that the utility resource plans in our sample do not always consider a full range of renewable resource types. As shown in Table 1, most plans consider wind, and some also include geothermal and other resources, within candidate portfolios. Many renewable sources are ignored, or screened out earlier in the process. Though such an acute focus on primarily wind power may simplify modeling (and may also make some sense if the mix of renewable resources will ultimately be determined based on the outcome of open solicitations), such an analytic approach may forfeit any insights (e.g., transmission upgrade needs) that might be gained by modeling a variety of specific renewable resources.

More importantly, all of the resource plans in our sample exogenously define the maximum amount of renewables that can be selected, either by establishing constraints on the optimization model, by pre-defining candidate portfolios, or by accepting only a certain amount of wind even if analysis results suggest that higher levels of penetration are warranted. Figure 3 illustrates the exogenous caps for wind power additions, both in terms of incremental capacity and incremental percentage of peak load. In some cases, the maximum permissible amount of incremental wind is relatively small, and in many cases these caps limit the amount of wind power included in the

preferred portfolio (e.g., NorthWestern 2004, PSE 2003, PSCo Original, Avista 2003; and probably Sierra Pacific and Nevada Power). This raises the possibility that, in some cases, wind power may not have been included in candidate portfolios over a broad enough range, potentially leading to sub-optimal results.

Additionally, in four of the five original California and Nevada plans, the existence of state RPS policies led to a pre-defined amount of renewable energy in the preferred portfolio (i.e., to achieve, but not exceed compliance), effectively serving to cap planned renewable resource procurement (see Table 1). None of the California or Nevada plans publicly provides any economic analysis of the potential value of purchasing renewable energy at a level that exceeds the state's RPS requirements; nor do many of these plans present economic analysis of which renewable sources might best meet their RPS-driven needs.<sup>6</sup> Again, while this basic approach may be functional in RPS-states, it forfeits any insights that might be gained by modeling specific resources, and fails to provide a utility's regulators or external stakeholders with information that might be useful in establishing planning and procurement expectations.

**Table 1. Summary of Candidate Portfolios**

Utility	Number of Candidate Portfolios	Candidate Portfolios with New Renewables	Types of Renewables in Candidate Portfolios	Required to Meet RPS	Evaluated Renewables Above RPS
<b>Avista 2003</b>	<i>Used optimization process*</i>		Wind	No	N/A
<b>Idaho Power 2004</b>	12	9	wind, geothermal	No	N/A
<b>NorthWestern 2004</b>	12	7	Wind	No†	N/A
<b>PacifiCorp 2003</b>	26	26	wind, geothermal	No±	N/A
<b>PacifiCorp 2004</b>	24	0	N/A	No±	N/A
<b>PGE Final Act. Plan 2004</b>	26	26	Wind	No	N/A
<b>PSCo 2003</b>	<i>Used optimization process*</i>		Wind	No†	N/A
<b>PSE 2003</b>	91	49	Wind	No	N/A
<b>PSE 2005</b>	4	4	wind, biomass	No	N/A
<b>Nevada Power 2003</b>	26	26	unspecified, unspecified solar	Yes	No
<b>Sierra Pacific 2004</b>	12	12	wind, geothermal, unspecified solar	Yes	No
<b>PG&amp;E 2004</b>	1**	1	wind repowering, unspecified	Yes	No‡
<b>SCE 2004</b>	1**	1	Unspecified	Yes	No
<b>SDG&amp;E 2004</b>	1**	1	wind, geothermal, biomass, biogas, hydro, solar	Yes	Yes

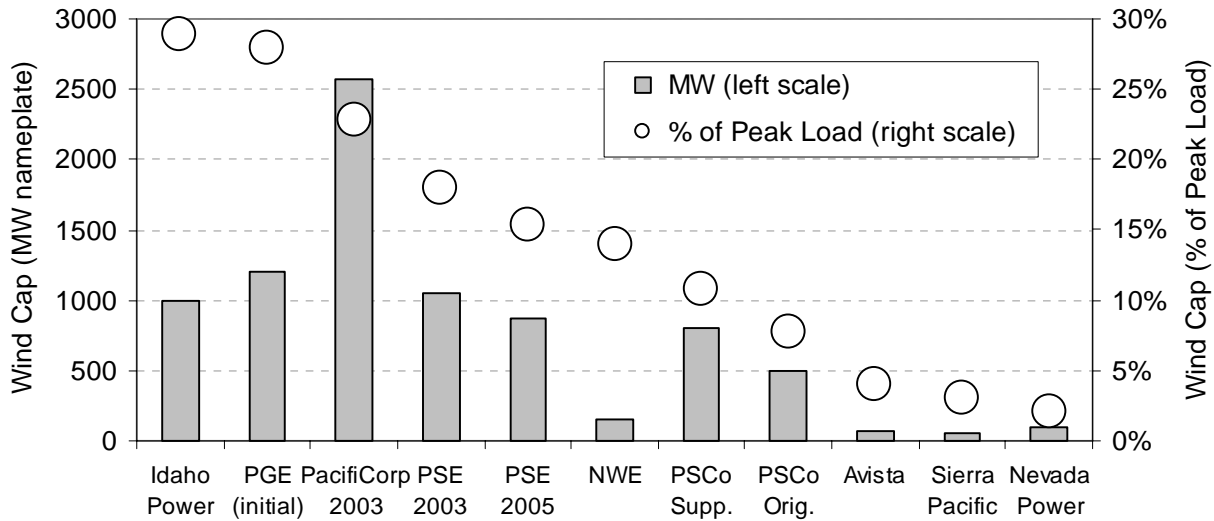
\*No candidate portfolios were developed. Instead, for each scenario examined, a capacity expansion model optimized a single portfolio based on user-defined market conditions and constraints.

\*\*Each of the three California utilities developed slightly different candidate portfolios based on different load growth scenarios. This is ignored here, because these portfolios did not significantly vary.

±PacifiCorp serves a small segment of California, but the vast majority of its sales are not covered by an RPS.

†At the time their IRPs were created, neither PSCo nor NorthWestern faced an RPS.

‡PG&E considered renewable energy additions above the state's RPS in its 2005 renewables procurement plan.



**Figure 3. Exogenous Caps on Wind Power Capacity within Candidate Portfolios**

## IV. Renewable Resource Cost and Performance Assumptions

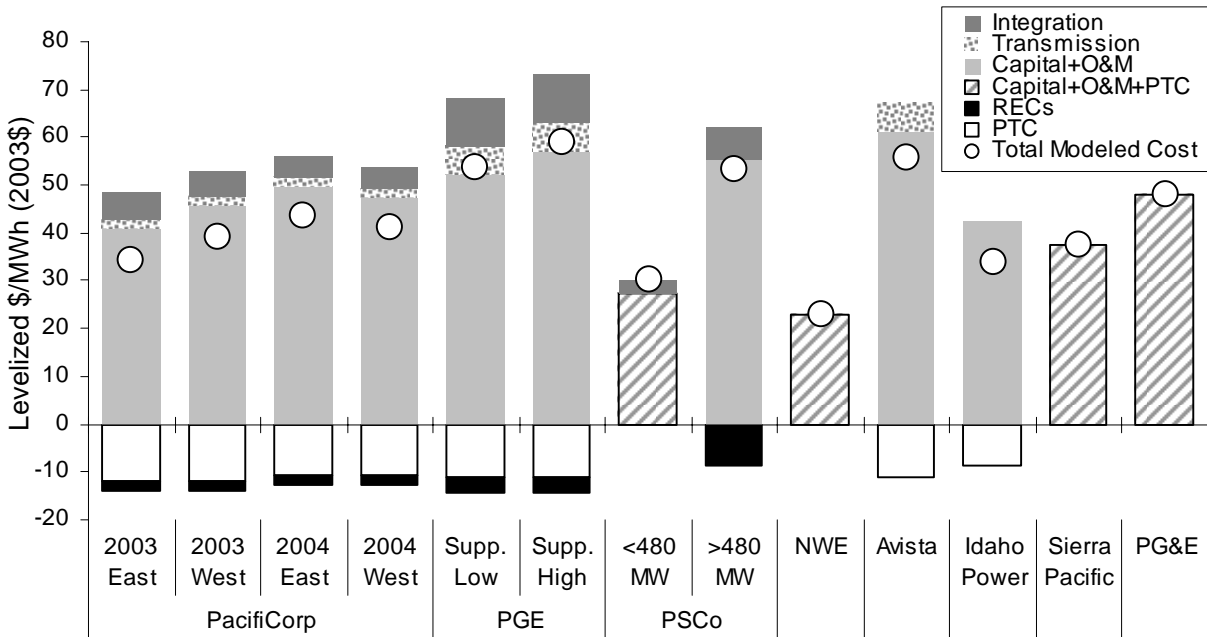
### A. The Modeled Cost of Wind Power

Also important to how renewable energy fares in IRP are assumptions about the cost and performance of various renewable technologies. Figure 4 breaks out the assumed levelized cost of wind power by component – i.e., busbar cost, transmission, and integration costs (as well as any assumptions about the value of renewable energy credits, or RECs) – where data are available. As shown, the total modeled levelized cost of wind power ranges from \$23/MWh to \$59/MWh. In some cases, wind power is assumed to be among the cheapest sources of energy considered in these plans. Not surprisingly, the total modeled cost of wind power has a strong influence on the amount of new wind included in preferred portfolios, with lower assumed costs generally leading to higher planned wind penetration (see Figure 5).

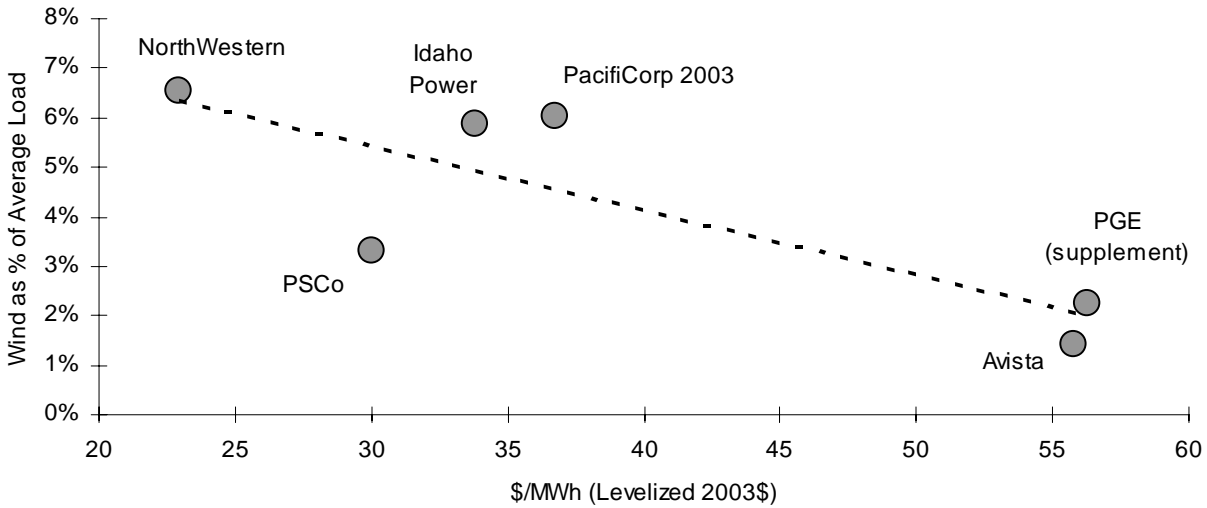
The assumed levelized busbar costs of wind power (which includes capital and O&M costs, as well as the value of the federal production tax credit, or PTC) range from \$23/MWh to \$55/MWh, and seem reasonable compared to other sources. Some resource plans, however, account for the PTC in a *pre-tax*, rather than *after-tax* manner, and thereby understate the value of the PTC by approximately \$7/MWh.<sup>7</sup> On the other hand, many of the plans assume that the PTC will remain available for a longer period of time than appears reasonable, thereby perhaps understating the likely cost of renewable energy in the longer term.

It is important to note that adverse exchange rate movements, coupled with rising steel prices, tight wind turbine manufacturing capacity, and a general rush to install wind projects prior to the then-scheduled expiration of the PTC at the end of 2005, have combined to push the installed cost of wind projects sharply higher in 2005; how long this higher price environment will persist is unclear. Past IRP assumptions for the cost of wind may therefore not be reflective of *current* costs; this potential disparity between utility expectations and current market reality could

negatively impact wind procurement efforts in the near term, and could result in higher cost assumptions in future resource plans.



**Figure 4. Wind Power Cost Assumptions**



**Figure 5. Modeled Wind Power Cost vs. Planned Wind Power Penetration**

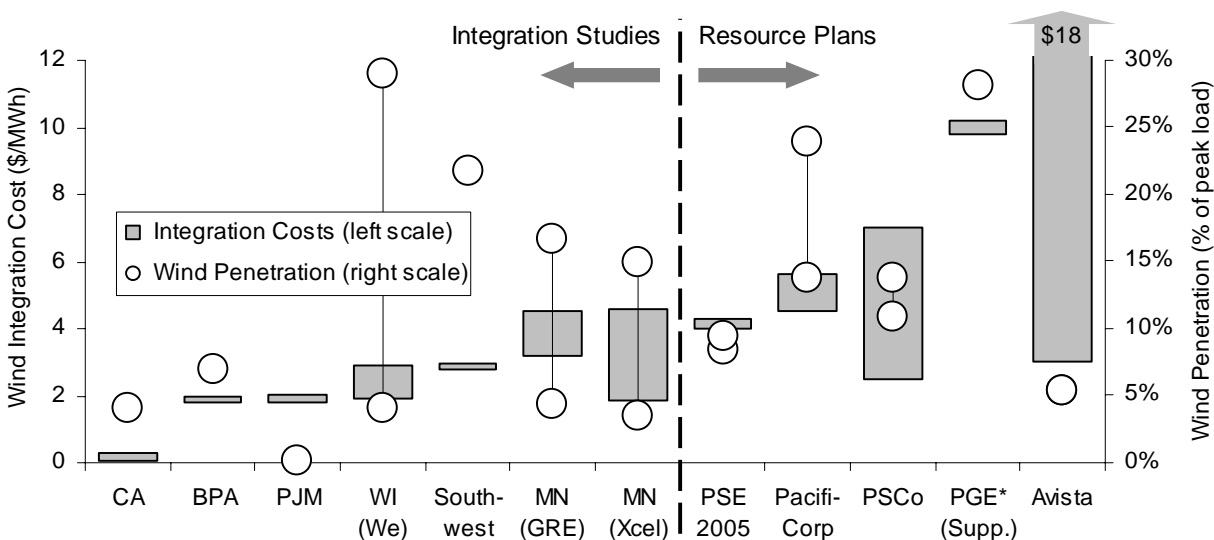
**B. Transmission, Integration, and Capacity Value**

Though many of the resource plans in our sample account for the cost of transmitting wind across *existing* power lines, the larger issue of expanding the transmission system to access greater quantities of renewable resources has, in many but not all instances, only been addressed



qualitatively. Particularly as wind additions increase in the West, it will be necessary to develop and incorporate into IRPs improved assessments of the transmission costs of accessing varying quantities of wind generation. This may allow resource plans to move away from strict and sometimes-arbitrary limits on the amount of wind additions allowed.

Utilities are using increasingly sophisticated tools to evaluate the integration costs of wind power. Compared to recent analytic studies, however, wind integration costs used in *some* of the utility resource plans appear to be conservative. Figure 6 illustrates this point: the range of costs (and corresponding wind penetration levels) estimated by recent wind integration studies is shown to the left of the dashed vertical line, while the range of costs assumed among our sample of resource plans (where data is available) is shown to the right of that line.<sup>8</sup> Still other utilities have assumed that such costs are negligible, and exclude these possible costs from consideration in their plans; additional studies to support such an assumption may be warranted.



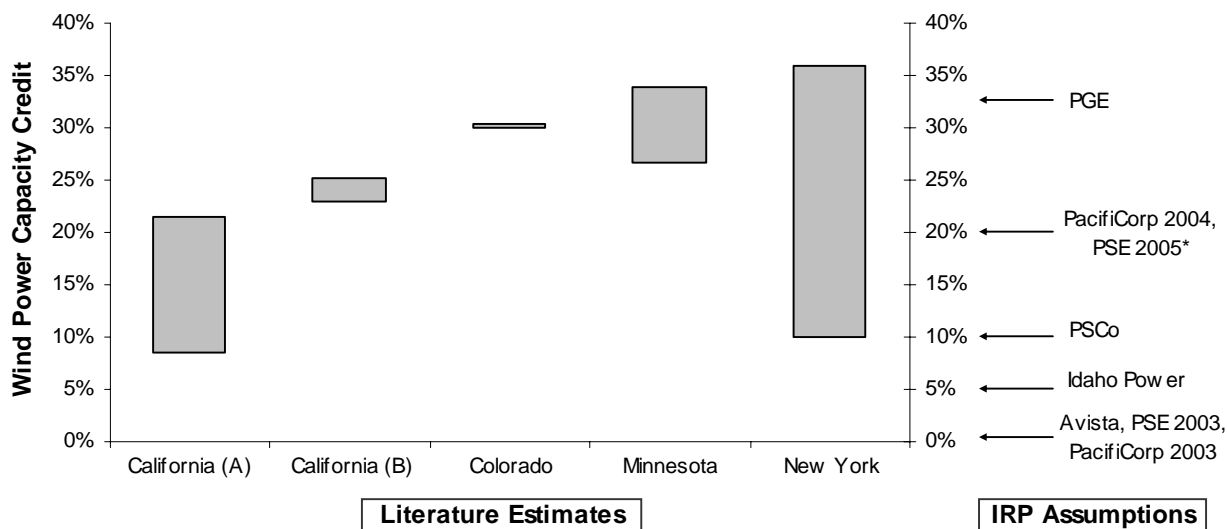
**Figure 6. Comparison of Integration Costs in Resource Plans and Integration Studies**

\*PGE estimates the cost of creating a flat, base-load block of power out of variable wind production, rather than simply the cost of integrating variable wind production. As such, its cost estimate is not directly comparable to the others.

Some utilities cite uncertainty over integration costs as a reason to cap the amount of wind power allowed into candidate or preferred portfolios. These caps – presented earlier in Figure 3 – are sometimes established at low, and somewhat arbitrary, levels, and highlight the need for *more* integration cost studies conducted at *higher* wind penetration levels. Until such studies are available, uncertainty over integration costs might best be modeled just like any other uncertain variable – using scenario and/or stochastic analysis – rather than through exogenous wind penetration caps.

Virtually all of the IRPs that explicitly assigned a capacity value to wind calculated that value in a different way, and only two utilities in our sample used effective load carrying capability (ELCC), viewed by many to be the most analytically rigorous way of quantifying capacity value.<sup>9</sup> Perhaps as a result, assumptions about wind’s capacity value range widely, from 0% to 33% (as shown by the arrows along the right-hand axis of Figure 7). Some of these assumptions

are lower than can be reasonably justified based on recent studies of wind’s ELCC (as shown by the grey bars in Figure 7). Further examination of wind’s capacity value, focusing on the use of ELCC, is warranted in future IRPs.



**Figure 7. Results from Recent Studies of Wind Power’s Capacity Value**

\*PSE 2005 assigns the lesser of 20% of nameplate capacity or two-thirds of the average capacity factor during January.

### C. Geothermal Cost Assumptions

Only a few of the utilities in our sample evaluated the cost of geothermal power, but in some cases these utilities found it to be competitive with wind, though assumed levelized costs ranged considerably: from \$35 to \$100/MWh, depending on the utility. This wide range of assumed costs is striking, and suggests that geothermal costs either vary significantly by region or site, or alternatively are poorly understood by utilities. If costs at the low end of the range are to be believed, however, then geothermal deserves a second look by more western utilities.

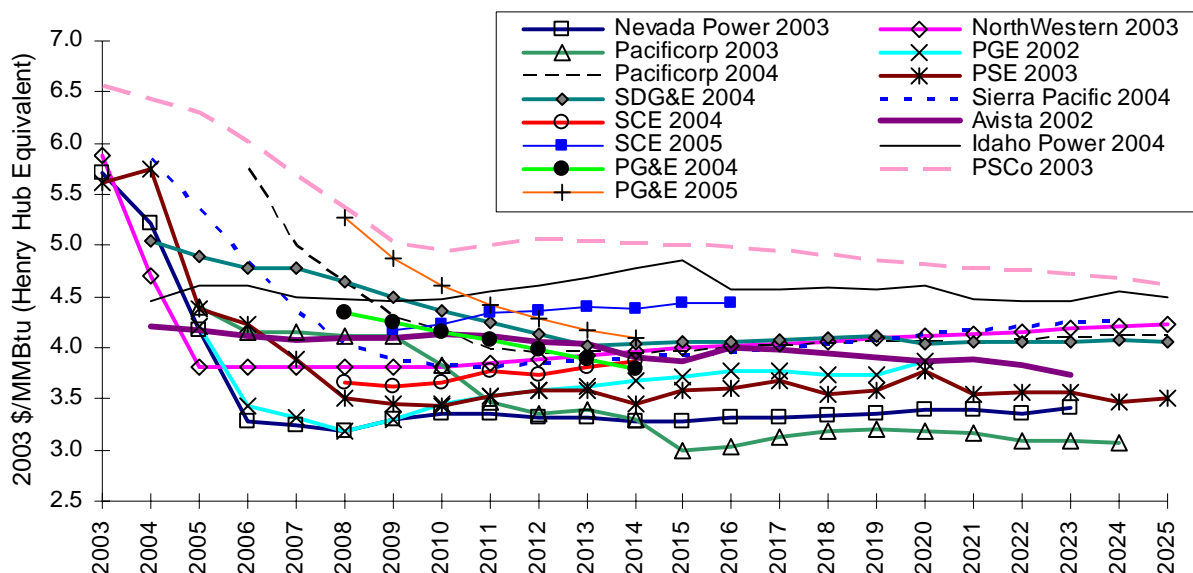
## V. Analysis of Natural Gas Price Risk

Analysts are increasingly calling attention to the benefits of renewable energy as a hedge against electricity sector risks, especially natural gas price risk and the risk of future environmental regulations. The treatment of these risks may therefore affect the degree to which IRPs rely on renewable energy. Here we review the treatment of natural gas price risk in western IRPs; the next section addresses environmental regulatory risks.

Assumptions for both the base-case natural gas price forecast and the expected long-term uncertainty in natural gas prices can be important in influencing resource decisions and the degree to which renewable energy is selected. Our review of western resource plans shows that all of the sampled utilities are taking natural gas price uncertainty seriously, and that the degree of analytic sophistication in applying risk analysis is increasing. Stochastic simulation is the

most common approach to analyzing these risks (used in 10 of the 12 plans), though a number of plans (9 of 12) use scenario analysis either as a supplement to, or a replacement for, stochastic simulation techniques.

Our review reveals that base-case gas-price forecasts vary considerably among the plans. In 2015, forecasted prices (in 2003 \$) range from \$3/MMBtu to \$5/MMBtu, depending on the plan (see Figure 8). These differences are striking, and can be attributed in part to different price forecasting methods, as well as the different times during which the forecasts were generated. These forecasted prices are also all well below current natural gas prices *and* current future price expectations, as revealed through the NYMEX futures markets, demonstrating the degree of inaccuracy that is possible when forecasting natural gas prices.



**Figure 8. Base-Case Gas Price Forecasts**

At least two factors should be considered when constructing base-case price gas forecasts. First, because future gas-price expectations can change rapidly, utilities should generally use the most-recent forecasts available. Second, the natural gas futures market can provide a useful benchmark against which to compare natural gas price forecasts (at least over the near-to-medium term – longer-term forecasts unfortunately have no such frame of reference), and base-case forecasts that diverge significantly from this benchmark warrant explanation and scrutiny.

Even with best efforts to construct a base-case forecast, poor historical forecast accuracy suggests that little weight should be placed on such gas-price forecasts. Alternative future price paths that vary by at least \$2/MMBtu higher or lower than the base-case forecast are certainly plausible. Though price distributions with wide uncertainty bounds are now used in a number of resource plans, some utilities appear to not be employing a wide enough range of future gas price scenarios. In other instances, resource plans offer too little information to assess whether the resulting price distribution is sufficiently wide. Though a few utilities have cited the proprietary nature of private forecasts as justification for not disclosing such information, other utilities freely report on the private sector forecasts used in their plans. There appears to be no

compelling reason for keeping such forecasts, or the resulting stochastic derivations, confidential.

Finally, although recent modeling studies have shown that, by reducing demand for natural gas, renewable energy deployment may put downward pressure on natural gas prices and consumer natural gas bills,<sup>10</sup> none of the plans in our sample directly account for this potential impact. This “oversight” may be reasonable because the effect of any *single* utility’s investments in renewable energy on *that* utility’s gas prices is likely to be minor. This effect is better considered in a regional setting, where the impact of *aggregate* renewable energy investment on *region-wide* gas prices can be more significant. Though it is debatable whether renewables (and other non-gas resources) should be given credit in *electricity* IRP for reducing consumer *natural gas* bills, overall rate stability is one of the goals of IRP, and one might therefore reasonably question why these markets are not analyzed in a more integrated fashion.

## VI. Analysis of Environmental Compliance Risk

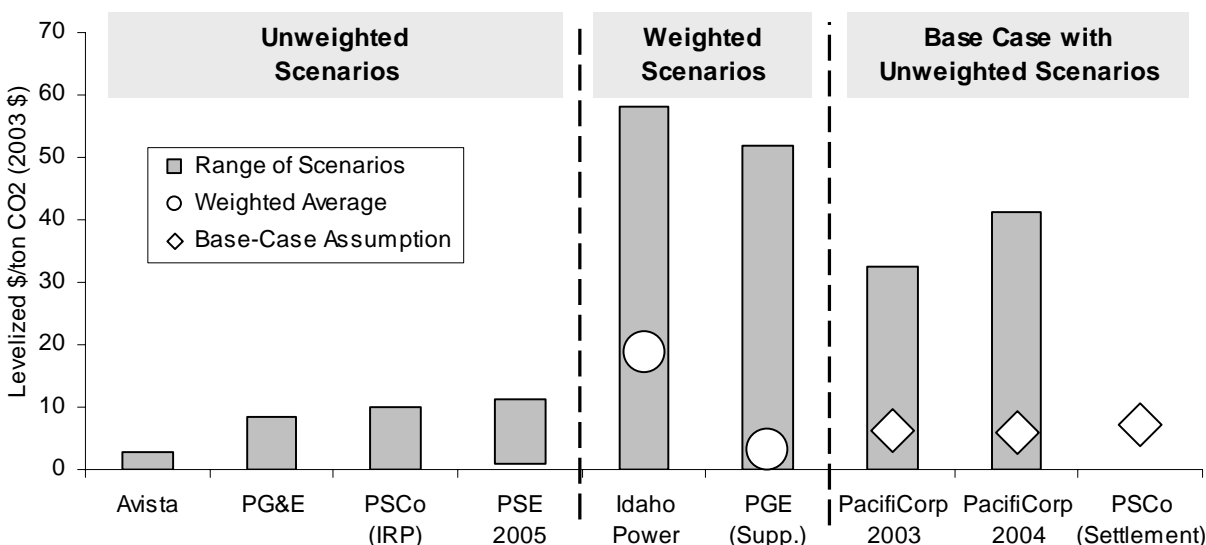
The risk of new or more stringent environmental regulations over the IRP planning horizon is significant. Utility resource plans should therefore evaluate this risk, and ideally mitigate it (if found to be cost effective) through resource portfolios that minimize the cost impacts of current and future regulations. Resource portfolios containing significant amounts of renewable generation are one way to help to reduce these risks.

The risk of future carbon regulations – which could plausibly increase the future cost of coal power by more than \$10/MWh – is arguably most significant among all environmental regulatory risks. As a result, seven of the twelve utilities in our sample specifically analyzed this risk. And with each of the California IOUs, as well as NorthWestern Energy in Montana, now also obligated to account for the possibility of future carbon regulations, just two utilities in our sample – Nevada Power and Sierra Pacific – currently ignore this risk in their planning.

In contrast to the near-uniformity with which western IRPs are taking on (or are now required to take on) the challenge of evaluating the risk of future carbon regulation, there is a great deal of inconsistency in *how* carbon risk is analyzed among the plans that we examined.<sup>11</sup> As shown in Figure 9, plans have generally adopted one of three approaches: (1) scenario analysis with no probabilities assigned, (2) probabilistic scenario analysis, and (3) inclusion of carbon risk in the base-case scenario. This variety of approaches is not surprising given the level of uncertainty about the stringency and timing of future carbon regulations. State regulators may, however, want to encourage consistency in the analysis approach and assumptions used, at least among those utilities within their state. In addition, to ensure that the risk of carbon regulation is adequately considered in portfolio selection, utilities should arguably be encouraged to include this possibility in their “base-case” analysis, with side-cases examining both greater and lower levels of regulatory stringency (see, e.g., PacifiCorp’s 2003 or 2004 IRP).

As also suggested by Figure 9, determining an appropriate range of carbon compliance costs can be challenging: resource plans within our sample assume a levelized cost of anywhere from \$0 to \$58/ton-CO<sub>2</sub>. The stringency of carbon regulation scenarios can, however, be benchmarked to

an existing modeling literature. Though there continues to be substantial variation within this literature, the range of compliance costs revealed is broadly consistent with the range used in our sample of resource plans. Some of the *specific* plans, however, may not be evaluating a sufficiently broad range of carbon regulation scenarios. Avista, for example, only evaluates a carbon regulation scenario in which a carbon tax of \$2.7/ton-CO<sub>2</sub> is applied (levelized, 2003\$). PGE, on the other hand, does evaluate a broader range of carbon costs, but weights the scenarios such that the weighted-average carbon cost is quite low, at \$3/ton-CO<sub>2</sub> (levelized, 2003\$).



**Figure 9. Summary of Carbon Regulation Scenarios in Western Resource Plans**

Contrary to their treatment of carbon risk, western IRPs do not devote as much attention to the possibility of more stringent criteria air pollution regulations. The risk of future, more stringent SO<sub>2</sub>, NO<sub>x</sub>, mercury, and particulate regulations is only clearly considered in *two of the twelve* plans that we reviewed (PacifiCorp and PSCo). Though more stringent criteria pollutant regulations may not have the same impact on portfolio selection as the possibility of carbon regulations (due the relatively smaller expected cost impacts of such regulations), analysis of this risk still has merit. As with carbon, benchmarks for the cost of complying with future air pollution regulations are readily available from the modeling literature, and could be utilized.

## VII. Balancing Portfolio Cost and Risk

Within the resource planning process, utilities ultimately have a responsibility to evaluate and balance the expected cost and risk of candidate portfolios on behalf of ratepayers, choosing the portfolio with the “best” cost-risk combination. The way in which this cost/risk tradeoff occurs is particularly important for renewable sources, which might be characterized as low risk, yet potentially higher cost, resource options.

Our review reveals that resource plans vary considerably in how they define expected risk, and how they balance the expected cost and risk of different candidate portfolios. In selecting a “preferred” portfolio, a utility would ideally review consumer preferences for cost-risk tradeoffs,

and select the candidate portfolio that fits most closely with the risk preferences of the majority of its customers. This approach, however, is rarely used. Instead, in all of the cases we reviewed, the cost-risk tradeoff (if made) is based on the subjective judgment of each utility, informed by any counsel provided by the utility's regulators or external stakeholders.

Moreover, virtually all of the plans in our sample used the utility's weighted average cost of capital (WACC) as the relevant discount rate in calculating the expected cost of different portfolios. Given uncertainty as to whether the WACC is an appropriate discount rate to use when making decisions on behalf of electricity customers,<sup>12</sup> we recommend that sensitivity analysis be conducted on this important variable.

Separate from, but just as important as, the questions of how to measure and weight portfolio cost and risk is the question of *how* and *when* within the IRP process to assess the cost/risk tradeoff. Some plans evaluate this tradeoff *prior to* conducting scenario analysis, with potentially significant consequences for renewable energy.

For example, fuel price risk has typically been addressed through stochastic analysis, ensuring that fuel price risk will impact base-case results early in the analytic process. In contrast, carbon risk has typically been addressed later in the process through scenario analysis, often being conducted on just a few candidate portfolios selected for further scrutiny *based on their attractive cost/risk tradeoff*. In other words, the cost/risk tradeoff has often been made – in part based on consideration of fuel price risk – *before carbon risk is considered*, in which case carbon risk is sometimes relegated to helping to distinguish between a few finalist portfolios.

The fact that fuel price risk appears to take precedence over carbon risk in some cases becomes important when one considers that the simplifying assumption made by many plans to model renewables primarily or solely as wind power, in conjunction with conservative assumptions about the capacity value of wind and the need for gas-fired peaking plants to integrate wind into the system, sometimes results in so-called “renewables” portfolios being heavily laden with gas-fired generation. As a result, some of the “renewables” portfolios in our IRP sample exhibit as much or more exposure to natural gas price risk than other portfolios (e.g., PacifiCorp 2003, PSE 2003, Idaho Power).

This somewhat counterintuitive result has, in some cases, shifted resource selection towards coal-fired generation early in the analytic process. By the time carbon risk is assessed, some renewables portfolios – i.e., those best able to mitigate carbon risk – may have already been weeded out of the process, potentially leaving the model to choose from among a number of sub-optimal portfolios.

This situation highlights the need for a more holistic assessment of risk, and approach to the cost/risk tradeoff. The sequential, winnowing approach currently taken by many plans eases computational burdens, but also may lead to results that are more a function of the *manner* or *order* in which different risks were assessed rather than of the potential *likelihood* or *magnitude* of the risk itself. If some risks are better-suited for scenario rather than stochastic analysis, then steps should be taken to ensure that the results from the scenario analysis are integrated into the overall process. Otherwise, scenario analysis, and the risks analyzed with that technique, may

end up as a mere sideshow to stochastic analysis. Related, a large and varied set of candidate portfolios should be evaluated for their ability to mitigate risks; otherwise, analysis results may be unduly affected by the pre-selection of possible candidate portfolios.

## **VIII. Conclusion**

Formal resource planning processes can help utilities and their regulators to consistently and fairly assess a wide range of supply- and demand-side measures in meeting customer needs. Our review of the planning efforts of twelve western utilities reveals that resource plans are becoming increasingly sophisticated in their treatment of renewable resources and the costs and risks that they both entail and mitigate. Many analytical improvements have been made in just the past few years.

As highlighted in this article, however, further improvements are still possible, and will enable utilities to more accurately assess and weigh the costs, benefits, and risks of different resource options. Resource plans in RPS states, for example, should consider evaluating renewable resources as an option above and beyond the level required to satisfy RPS obligations. Resource planners may also wish to explore a broader array of renewable resource options, and not focus exclusively or primarily on wind power. With natural gas prices expected to remain high for some time, and with the PTC now extended to a broader array of renewable sources, additional renewable technologies may be competitive with conventional generation in some instances.

The value of the federal production tax credit for renewable energy, and its risk of permanent expiration, could also be more accurately addressed. Our analysis reveals that some plans are underestimating the near-term value of the credit, while most plans are overestimating the likely availability of the credit beyond the next few years. Additionally, methods for evaluating wind integration and transmission costs, and capacity value, should continue to be refined and applied at successively higher wind penetration levels in resource planning efforts. In doing so, resource planners should be able to eliminate exogenous and sometimes arbitrary caps on wind penetration, replacing those caps with realistic estimates of the incremental total cost of wind power expansion.

Though resource plans are becoming increasingly sophisticated in their treatment of risks, it is important that the high degree of natural gas price uncertainty is fairly addressed in resource planning efforts: a broad range of future fuel costs should be considered. In addition, to accurately evaluate the benefits of certain resource options in mitigating this risk, a large number and diverse set of candidate portfolios should be considered. Environmental compliance risks are also being addressed in present resource planning efforts, but improvements in the consistency and comprehensiveness of this analysis are possible. Overall, steps should be taken to ensure that each risk has, as is warranted or appropriate, an opportunity to impact portfolio selection. Finally, to help utilities make the difficult tradeoffs between the expected cost and risk of different candidate portfolios, utilities and regulators might consider conducting research to further evaluate ratepayer risk preferences.

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<sup>1</sup> Formal resource planning (sometimes called portfolio management) may also be important in markets with retail electric competition, at least for those customers that have chosen not to switch suppliers.

<sup>2</sup> Bolinger, M. and R. Wiser. 2005. "Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans." LBNL-58450. Berkeley, Calif.: Lawrence Berkeley National Laboratory. <http://eetd.lbl.gov/ea/ems/reports/58450.pdf>

<sup>3</sup> This article does not address in detail the specific modeling techniques that are – or should be – used by electric utilities in evaluating renewable energy options. For an earlier treatment of these issues, see Logan, D.M., Neil, C.A., Taylor, A.S., Lilienthal, P. 1995. "Integrated Resource Planning with Renewable Resources." *The Electricity Journal*, 8(2): 56-66.

<sup>4</sup> Not surprisingly, the plans vary in the availability and completeness of the data released, and our ability to summarize the treatment of renewable energy in each of the plans is therefore somewhat limited. Also note that several utilities – most notably PGE and PSCo, but also a few others – filed one or more supplements to their initial resource plans, and in such cases this article draws upon information contained in the initial filing as well as in any subsequent revisions, as necessary or appropriate. See op cit. 2 for a more detailed identification of the specific resource plans and filings that we reviewed.

<sup>5</sup> Note, however, that for many utilities resource planning is an indicative process – the outcome of which does not limit further analysis or acquisition of any renewable or other resources – and therefore that sub-optimal modeling results may not necessarily lead to sub-optimal procurement decisions.

<sup>6</sup> All renewable energy projects would generally be eligible to participate in future solicitations, however, even if not explicitly included in the resource plans. In addition, California's utilities, in their 2005 renewable energy procurement plans, demonstrated greater analysis of various renewable energy options, and PG&E and SDG&E presented illustrative plans that would lead to over-compliance with the state RPS.

<sup>7</sup> Because the PTC *directly* reduces the amount of income taxes paid, it should be thought of as providing \$18/MWh (2003\$) of *after-tax* income. The amount of *pre-tax* income required to yield \$18/MWh of *after-tax* income is  $\$18/(1-\text{marginal tax rate})$ , or \$27.7/MWh assuming a 35% marginal income tax rate. At a 7% real discount rate, \$27.7/MWh for 10 years equals an equivalent PTC value of \$18.4/MWh levelized over 20 years, and \$15.7/MWh when levelized over 30 years. These values better reflect the true value of the PTC to most wind projects.

<sup>8</sup> For more information on the integration cost studies portrayed in Figure 6, as well as the capacity credit studies portrayed in Figure 7, see op cit. 2.

<sup>9</sup> Milligan, M. and K. Porter. 2005. "Determining the Capacity Value of Wind: A Survey of Methods and Implementation." Proceedings of *WINDPOWER 2005*, Denver, Colorado, May 15-18, 2005; Kahn, E. 2004. "Effective Load Carrying Capability of Wind Generation: Initial Results with Public Data." *The Electricity Journal*, 17(10): 85-95.

<sup>10</sup> Wiser, R., Bolinger, M. and M. St. Clair. 2005. "Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Increased Deployment of Renewable Energy and Energy Efficiency." LBNL-56756. Berkeley, California: Lawrence Berkeley National Laboratory. <http://eetd.lbl.gov/ea/ems/reports/58450.pdf>

<sup>11</sup> For more information on how three western utilities evaluate carbon risk in their resource plans, see Bokenkamp, K, H. LaFlash, V. Singh, D. Bachrach Wang. 2005. "Hedging Carbon Risk: Protecting Customers and Shareholders from the Financial Risk Associated with Carbon Dioxide Emissions." *The Electricity Journal*, 18(6): 11-24.

<sup>12</sup> Awerbuch, S. 1993. "The Surprising Role of Risk in Utility Integrated Resource Planning." *The Electricity Journal*, 6 (3): 20-33; Awerbuch, S. 1995. "Market Based IRP: It's Easy!!!" *The Electricity Journal*, 8(3): 50-67.