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

Executive Summary

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Disclaimer

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Executive Summary

Introduction

Markets for renewable energy have historically been motivated primarily 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 (IRP).[1] Resource planning has re-emerged in recent years as an important tool for utilities and regulators, particularly in regions where retail competition has failed to take root. In the western United States, the most 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.

This report examines how twelve western utilities treat renewable energy in their recent resource plans.[2] In aggregate, these utilities supply approximately half of all electricity demand in the western United States. 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 identify methodological/modeling issues, and suggest possible improvements to methods used to evaluate renewable energy as a resource option.

Here we summarize the key findings of the report, beginning with a discussion of the planned renewable energy additions called for by the twelve utilities, 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.[3]

Planned Renewable Energy Additions

The most recent batch of western resource plans includes a significant amount of 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),[4] 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 ES-1 shows the cumulative,

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[1] Though we use the term "IRPs" (or more generally, "resource plans" or "plans") throughout this report, we acknowledge that terminology varies, and that not all of the utilities refer to their own filings as "IRPs."

[2] The twelve investor-owned utilities (IOUs) included in our sample include: 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).

[3] Not surprisingly, the plans vary in the availability and completeness of the data that are released, and our ability to summarize the treatment of renewable energy in each of the plans is therefore somewhat limited.

[4] PSCo and NorthWestern have become subject to an RPS since filing their most recent IRPs. Because the RPS was not in place at the time of IRP filing, we do not consider these utilities' planned additions to be RPS-driven.

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.

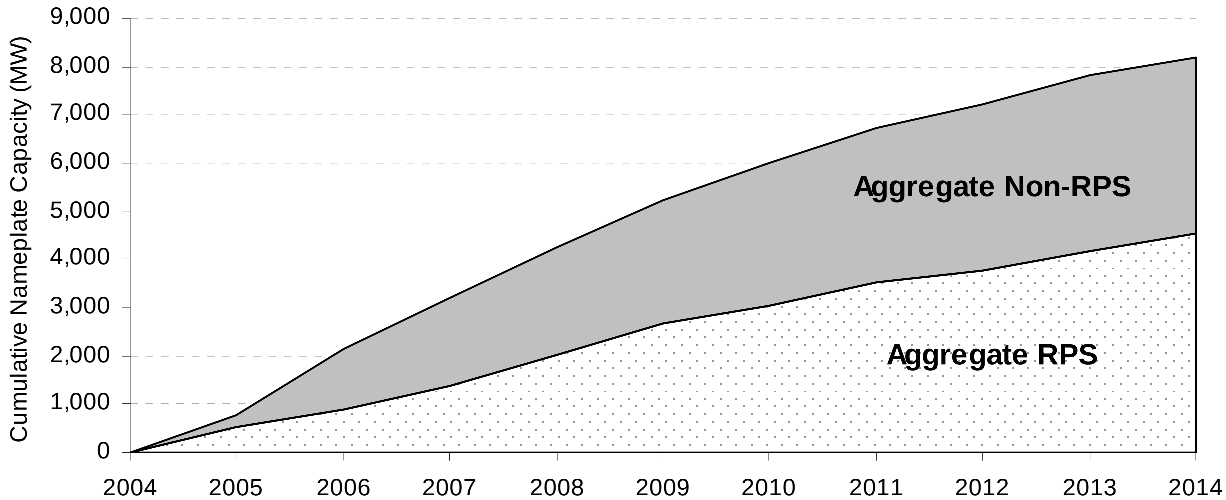

Figure ES-1. Planned Renewable Resource Additions in Twelve Western Resource Plans

Figure ES-2 breaks out the cumulative planned renewable additions from Figure ES-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 ES-1 and ES-2 clearly illustrate that non-RPS resource plans may themselves be a major driver of growth in new renewables; whether and to what degree these planned renewable additions are subsequently achieved is an important avenue of future study.

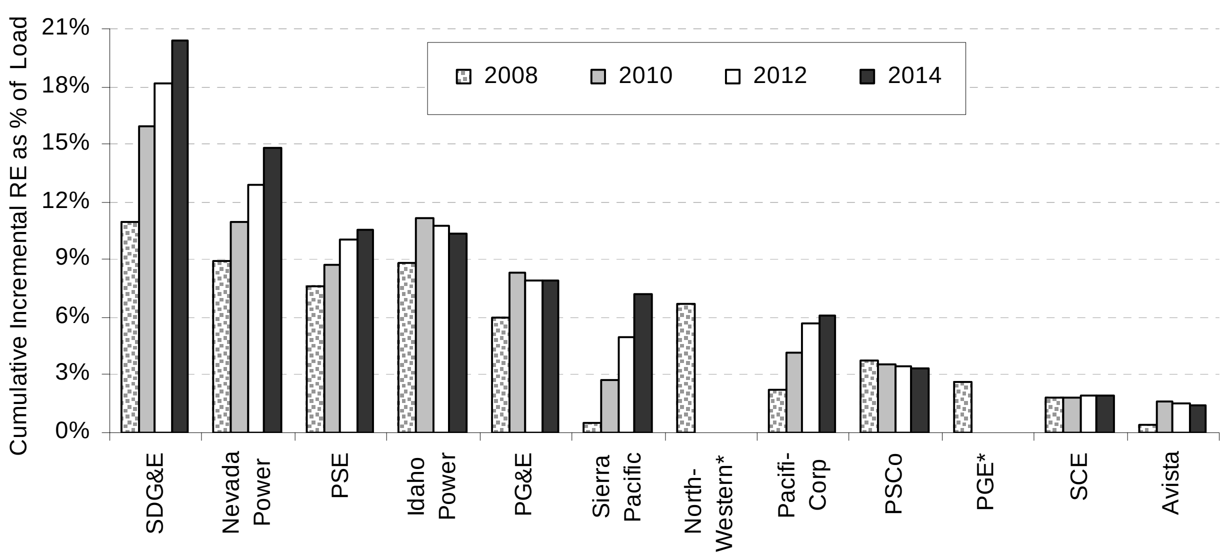

Figure ES-2. Cumulative Incremental Renewable GWh as a Percentage of Utility Load

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

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. 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.[5] Within this context, we make the following observations on how renewable energy is treated in candidate portfolio construction:

- **A full range of renewable options is not always considered in utility resource plans.** Most plans consider wind, and some also include geothermal and other sources, within candidate portfolios. Many renewable sources are ignored, however, or screened out earlier in the process. Even if open solicitations for renewable energy are subsequently held, such an analytic approach may forfeit any insights (e.g., transmission upgrade needs) that might be gained by modeling additional specific renewable resources.

- **Exogenous caps can limit the amount of renewable energy additions.** All of the IRPs in our sample exogenously define the maximum amount of renewable energy that can be selected, either by establishing constraints on the optimization model, by pre-defining candidate portfolios, or by only accepting a certain amount of wind even if analysis results suggest that higher levels of penetration are warranted. Figure ES-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.

- **State RPS policies sometimes "cap" the amount of renewable energy considered.** 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, effectively serving as a cap on *planned* renewable resource procurement. 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

[5] We do 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.

needs.[6] 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 information that might be useful in establishing planning and procurement expectations.

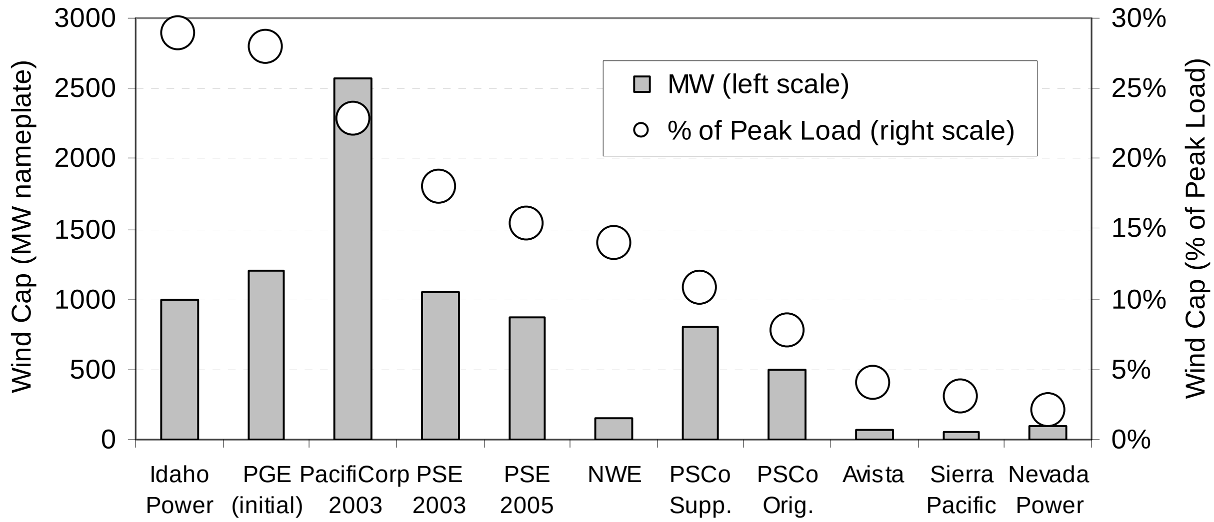

Figure ES-3. Exogenous Caps on Wind Power Capacity within Candidate Portfolios

Renewable Resource Cost and Performance Assumptions

Also important to how renewable energy fares in IRP are the cost and performance assumptions made for various renewable technologies. Based on our review of the wind power (and to a lesser extent, geothermal) cost and performance assumptions embedded in the resource plans, we make the following observations:

- **Assumptions for the total modeled cost of wind power can significantly affect wind power penetration.** Figure ES-4 breaks out the assumed cost of wind power by component, where data is available. As shown, the total modeled cost of wind power ranges from \$23/MWh to \$59/MWh. 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.

- **The range of levelized busbar costs assumed for wind generation appears to be reasonable.** The assumed busbar costs of wind power (capital, O&M, and PTC) range from \$23/MWh to \$55/MWh, and seem reasonable compared to other sources. It is important to note, however, 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

[6] Note that all renewable energy projects would generally be eligible to participate in future solicitations, even if not explicitly included in the resource plans. Also note that 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.

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.

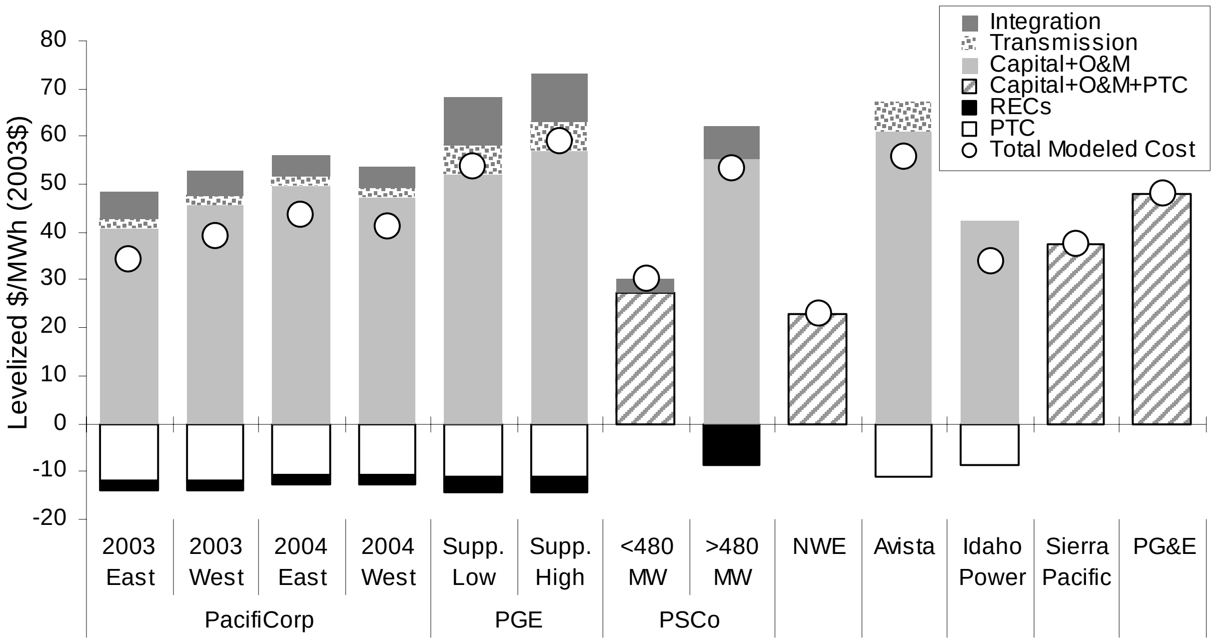

Figure ES-4. Wind Power Cost Assumptions

- **Some of the resource plans *understate* the value of the federal production tax credit (PTC), but *overstate* the likelihood of PTC extension over the planning horizon.** Some plans account for the PTC in a *pre-tax*, rather than *after-tax* manner. By doing so, these resource plans understate the value of the PTC by approximately $7/MWh. 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.

- **Transmission expansion costs are not widely evaluated.** 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 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 (as is sometimes current practice).

- **Integration cost assumptions by some utilities appear to be high, while others may be low.** 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 ES-5 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. Still other utilities, however, have assumed that such costs are negligible, and exclude these possible costs from consideration in their plans.

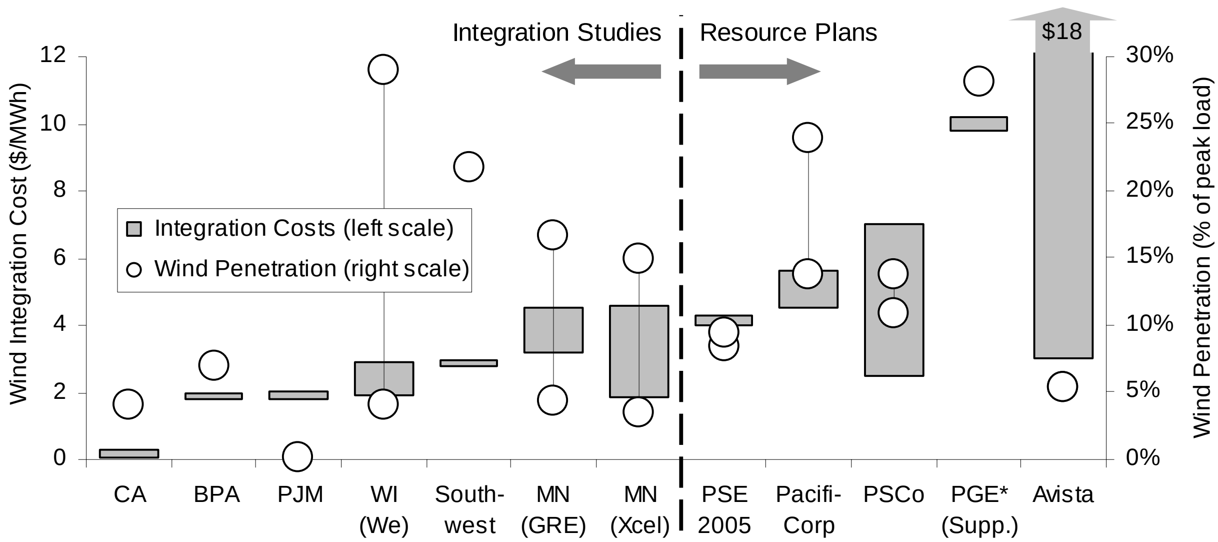

Figure ES-5. Comparison of Integration Costs in Resource Plans and Integration Studies
*PGE estimates the cost of creating a flat, base-load block of power out of variable wind production, rather than simply the cost of integrating variable wind production. As such, its cost estimate is not directly 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 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 be best modeled just like any other uncertain variable, using scenario and/or stochastic analysis, rather than through exogenous wind penetration caps.

- **In some cases, assumptions about wind's capacity value appear to be too low.** 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. 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 ES-6). Some of these assumptions are lower than warranted based on recent studies of wind's ELCC (as shown by the grey bars in Figure ES-6). Further examination of wind's capacity value, focusing on the use of ELCC, is warranted in future IRPs.

- **Geothermal costs are assumed to be competitive with wind in some cases, though the range of assumed costs is wide.** The wide range of assumed levelized costs for geothermal – from $35 to $100/MWh – 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 arguably deserves a second look by more western utilities.

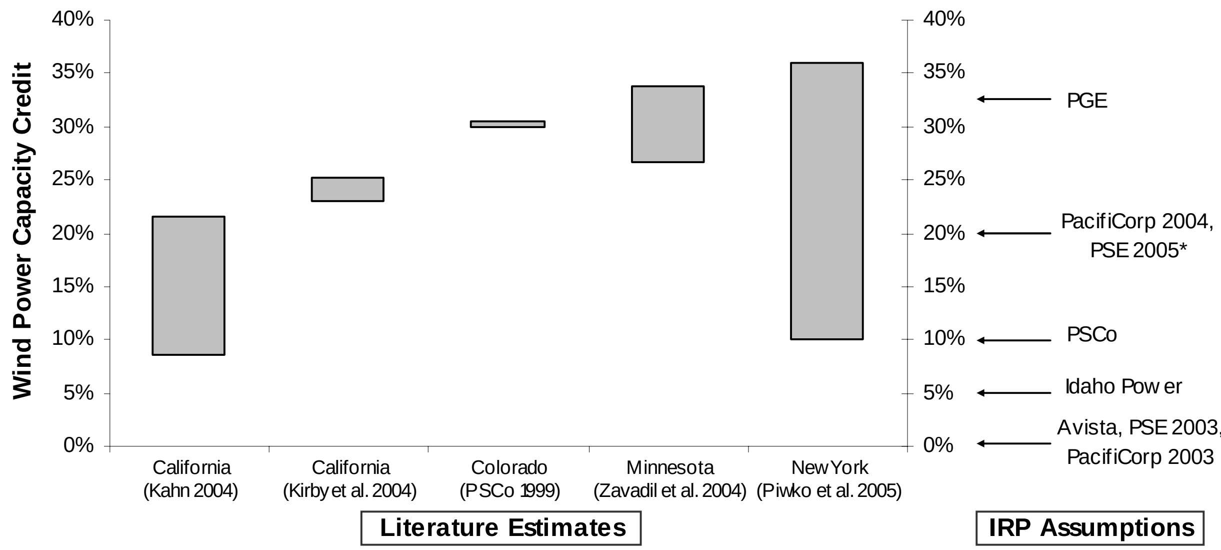

Figure ES-6. Results from Recent Studies of Wind Power's Capacity Value
**PSE 2005 assigns the lesser of 20% of nameplate capacity or two-thirds of the average capacity factor during January.*

Analysis of Natural Gas Price Risk

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 leads us to the following observations:

- **Base-case gas-price forecasts vary considerably among the plans**. In 2015, forecasted prices range from \$3/MMBtu to \$5/MMBtu, depending on the plan. These differences are striking, and can be attributed in part to different price forecasting methods and the different times during which the forecasts were generated. These forecasted prices are also all well below current pricing, and current future price expectations as revealed through the NYMEX futures markets. In constructing base-case price gas forecasts, we conclude that at least two factors should be considered. 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.

- **Some utilities may not be employing a wide enough range of future gas prices.** Poor historical forecast accuracy suggests that little weight should be placed on base-case gas-price forecasts. Alternative future price paths that vary by \$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 may not be employing a wide enough range of future gas price scenarios, and 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.

- **None of the plans evaluate the impact of increased renewable energy investments on natural gas prices.** Recent studies show that, by reducing demand for natural gas, renewable energy deployment may put downward pressure on natural gas prices and consumer natural gas bills. None of the IRPs in our sample directly accounted for this effect. 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 significant. While 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 reasonably question why these markets are not analyzed in a more integrated fashion.

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 evaluate this risk and, if it is expected to be significant, mitigate the risk through resource portfolios that minimize the cost impacts of current and future regulations. Resource portfolios with significant amounts of renewable energy may be able to help mitigate these risks. Our review of western IRPs leads us to the following observations:

- **Many of the western IRPs are taking on the challenge of evaluating and mitigating the risk of carbon regulation.** The risk of future carbon regulations – which could plausibly increase the 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.

- **There is a great deal of inconsistency in *how* carbon risk is analyzed among the plans that we examined.** As shown in Figure ES-7, 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 2003 or 2004).

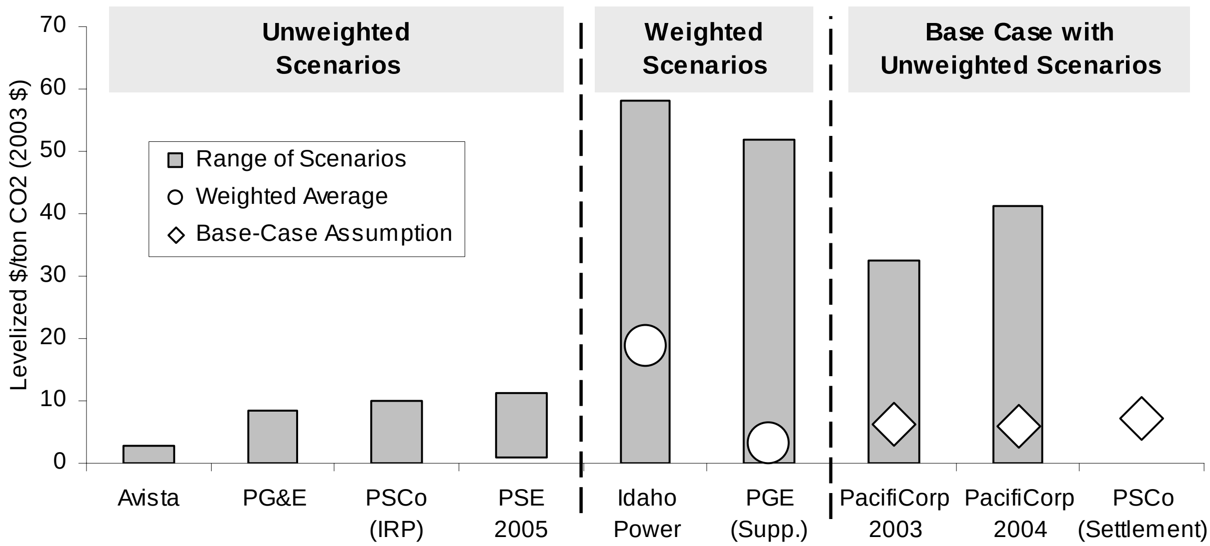

Figure ES-7. Summary of Carbon Regulation Scenarios in Western Resource Plans

- **The stringency of carbon regulation scenarios can be benchmarked to an existing literature, and some IRPs may be undervaluing this risk.** Determining an appropriate range of carbon compliance costs is challenging. As shown in Figure ES-7, resource plans assume a levelized cost of anywhere from \$0 to \$58/ton-CO_2. Though there continues to be substantial disagreement among analysts, the range of compliance costs shown in the broader modeling literature is 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_2 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_2 (levelized, 2003\$).

- **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_2, NOx, mercury, and particulate regulations is only clearly considered in *two of the twelve* plans that we reviewed. Though more stringent criteria pollutant regulations may not have the same impact on portfolio selection as the possibility of carbon 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.

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 are characterized in many plans as low risk, yet potentially higher cost, resource options.

Our review of resource plans reveals that those 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.

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

1) **The two main types of risk that renewable energy can help to mitigate are fuel price and environmental compliance (i.e., carbon) risk.** Though renewables are not the only supply-side resources to mitigate fuel price risk, renewables are unique among supply-side resources (barring nuclear) in their ability to mitigate carbon risk.

2) **Candidate portfolios intended as "renewables" portfolios have often ended up performing poorly with respect to fuel price risk.** 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-peaking plants to integrate wind into the system, has often resulted in so-called "renewables" portfolios being heavily laden with gas-fired generation. As a result, "renewables" portfolios have often exhibited as much or more exposure to natural gas price risk than other portfolios.

3) **Fuel price risk has taken some precedence over carbon risk.** 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.

4) **The precedence of fuel price over carbon risk may disadvantage renewable generation.** The fact that renewables portfolios have tended to perform poorly with respect to fuel price risk has, in some cases, shifted resource choice towards coal-fired generation early in the analytic process. By the time carbon risk is assessed, some renewables portfolios may have already been weeded out of the process.

These four considerations highlight the possible 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 the computational burden, but also may lead to results that are more of 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.

Finally, virtually all of the plans 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, we recommend that sensitivity analysis be conducted on this important variable.

Conclusions

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 executive summary, however, further improvements are still possible. Our most important conclusions are as follows:

1) Resource plans in RPS states should consider evaluating renewable resources as an option above and beyond the level required to satisfy RPS obligations.

2) Resource planners may wish to explore a broader array of renewable resource options.

3) The value of the federal production tax credit for renewable energy, and its risk of permanent expiration, could be more consistently addressed on an after-tax basis.

4) Methods for evaluating wind integration and transmission costs, and capacity value, should continue to be refined and applied at successively higher wind penetration levels.

5) Exogenous caps on wind penetration should potentially be eliminated, especially as analysis of wind integration and transmission costs, and capacity value, improve.

6) Resource plans would ideally evaluate a broad range of possible fuel costs, and subject a large number of candidate portfolios to such analysis (and risk analysis more generally).

7) Environmental compliance risks could be more consistently and comprehensively evaluated.

8) Steps should be taken to ensure that each risk has, as is warranted or appropriate, an opportunity to impact portfolio selection.

9) Utilities and regulators should conduct research to evaluate ratepayer risk preferences.

10) Though there may be instances in which redaction of commercially sensitive information is warranted, more consistent and comprehensive data presentation in utility resource plans would allow for far better external review.