

Pursuing Energy Efficiency as a Hedge against Carbon Regulatory Risks: Current Resource Planning Practices in the West

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ABSTRACT

Uncertainty surrounding the nature and timing of future carbon regulations poses a fundamental and far-reaching financial risk for electric utilities and their ratepayers. Long-term resource planning provides a potential framework within which utilities can assess carbon regulatory risk and evaluate options for mitigating exposure to this risk through investments in energy efficiency and other low-carbon resources. In this paper, we examine current resource planning practices related to managing carbon regulatory risk, based on a comparative analysis of the most-recent long-term resource plans filed by fifteen major utilities in the Western U.S. First, we compare the assumptions and methods used by utilities to assess carbon regulatory risk and to evaluate energy efficiency as a risk mitigation option. Although most utilities have made important strides in beginning to address carbon regulatory risk within their resource plan, we also identify a number of opportunities for improvement and offer recommendations for resource planners and state regulators to consider. We also summarize the composition and carbon intensity of the preferred resource portfolios selected by the fifteen Western utilities, highlighting the contribution of energy efficiency and its impact on the carbon intensity of utilities' proposed resource strategies. Energy efficiency and renewables are the dominant low-carbon resources included in utilities' preferred portfolios. Across the fifteen utilities, energy efficiency constitutes anywhere from 6% to almost 50% of the preferred portfolio energy resources, and represents 22% of all incremental resources in aggregate.

Introduction

The long economic lifetime and development lead-time of electric infrastructure investments requires that utility resource planning consider potential costs and risks over a lengthy time horizon. One long-term and potentially far-reaching financial risk currently facing the electricity industry is the uncertain cost of future carbon dioxide (CO₂) regulations. Recognizing the potential magnitude of this risk, utilities are beginning to actively assess carbon regulatory risk within their resource planning processes, and to evaluate options for mitigating that risk – for example, by increasing their reliance on energy efficiency to meet future resource needs. Given the relatively recent emergence of this issue, however, and the rapidly changing political landscape, methods and assumptions used by utilities to analyze carbon regulatory risk, and to evaluate energy efficiency as a hedge against this risk, vary considerably across utilities.

In this paper, we characterize and assess the treatment of carbon regulatory risk in utility resource planning, through a comparative analysis of the most-recent resource plans filed by fifteen investor-owned and publicly-owned utilities in the Western U.S. (see Table 1).¹

¹ This paper draws upon a longer report addressing the treatment of carbon regulatory risk in Western utility resource plans (Barbose et al. 2008), which builds upon previous work by LBNL examining utility resource planning practices in the West (Bolinger & Wiser 2005; Hopper, Goldman & Schlegel 2006).

Together, these utilities account for approximately 60% of retail electricity sales in the West, and cover nine of eleven Western states. First, we examine utilities’ approaches to a number of key analytical issues that affect their ability to value energy efficiency as a hedge against carbon regulatory risk, including:

- Their assumptions about future carbon regulations and emission prices,
- The size of the energy efficiency targets that utilities considered and the extent to which they evaluated the associated avoided carbon costs and risks,
- The extent to which utilities considered indirect impacts of carbon regulations that could have potential significance for the level of energy efficiency deemed cost-effective.

Second, we summarize the composition and carbon intensity of the preferred resource portfolios selected by these fifteen utilities, highlighting the contribution of energy efficiency and its impact on the carbon intensity of utilities’ proposed resource strategies. Finally, we conclude with several recommendations related to the analysis of carbon regulatory risk, for utility resource planners and state regulators to consider.

Table 1. Utility Resource Plans Reviewed

Utility	Service Territory	Year of Resource Plan	Portfolio Construction Period
Avista	Idaho, Washington	2007	2008-2027
Idaho Power	Idaho, Oregon	2006	2006-2025
Los Angeles Department of Water and Power (LADWP)	California	2006	2006-2025
Nevada Power	Nevada	2006	2007-2026
NorthWestern	Montana	2007	2008-2027
PacifiCorp	Oregon, Utah, Wyoming, Washington, Idaho, California	2007	2007-2016
Pacific Gas & Electric (PG&E)	California	2006	2007-2016
Portland General Electric (PGE)	Oregon	2007	2008-2012
Public Service Company of Colorado/Xcel (PSCo)	Colorado	2007	2008-2020
Puget Sound Energy (PSE)	Washington	2007	2008-2027
Southern California Edison (SCE)	California	2006	2007-2016
San Diego Gas & Electric (SDG&E)	California	2006	2007-2016
Seattle City Light	Washington	2006	2007-2026
Sierra Pacific	Nevada, California	2007	2008-2027
Tri-State Generation and Transmission	Colorado, New Mexico, Wyoming, Nebraska	2007	2007-2025

Carbon Regulations and Emission Prices Modeled in Utility Resource Plans

The starting point in quantitatively evaluating carbon regulatory risk is to develop specific assumptions about the carbon regulations that could plausibly be implemented over the lifetime of the resource investments considered in the plan. Given the high degree of uncertainty in the nature and timing of future carbon regulations, utilities often develop a range of alternate assumptions to evaluate through scenario analyses. In this section, we describe the carbon regulations that utilities in our sample posited when estimating the cost of alternate candidate portfolios, with particular attention to their projections of potential carbon emission prices under

a carbon tax or cap-and-trade system.

Utility Projections of Carbon Emission Prices

With only one exception, all of the utilities in our review – in many cases following directives from state public utility commissions – included a future carbon tax or cap-and-trade program in their portfolio analysis, either as part of their base-case scenario, in alternate scenarios, or both. In California and Oregon, the state public utility commissions (PUCs) have specified particular carbon emission prices that investor-owned utilities are to use in their resource planning analyses. Where state PUCs have not provided specific guidance or requirements regarding carbon price assumptions, utilities often relied on analyses of recent federal cap-and-trade policy proposals as the basis for their carbon price assumptions. The most common example, five utilities (Avista, Nevada Power, PGE, PSE, and Sierra Pacific) used the safety-valve price initially recommended by the National Commission on Energy Policy (NCEP) as the basis for their carbon emission prices in at least one scenario. It is perhaps of note that no utilities developed future carbon price projections based specifically on existing emission reduction targets already adopted in many Western states, despite the fact that these policies could arguably represent a more reliable indicator of the near-term carbon regulation regime than a federal carbon tax or cap-and-trade program.

In Figure 1, we compare utilities' base-case and alternative CO₂ price projections in terms of the levelized price over the period 2010-2030. These levelized prices capture differences in both the overall magnitude and the timing of utilities' price projections. We benchmark these assumptions against the Energy Information Administration (EIA)'s projections of carbon emission allowance prices under three federal cap-and-trade policy proposals: the original 2003 McCain-Lieberman bill, S.139 (EIA 2003); draft legislation prepared by Senator Bingaman in late-2006, based on the original NCEP recommendations (EIA 2007a); and the 2007 McCain-Lieberman bill, S.280 (EIA 2007b). To capture a wider set of potential policies and modeling methods and assumptions, we also show the low-, mid-, and high-range CO₂ price projections developed by Synapse Energy Economics (Johnston et al. 2006). Synapse developed these projections by synthesizing the results of eleven modeling studies of five federal cap-and-trade proposals.

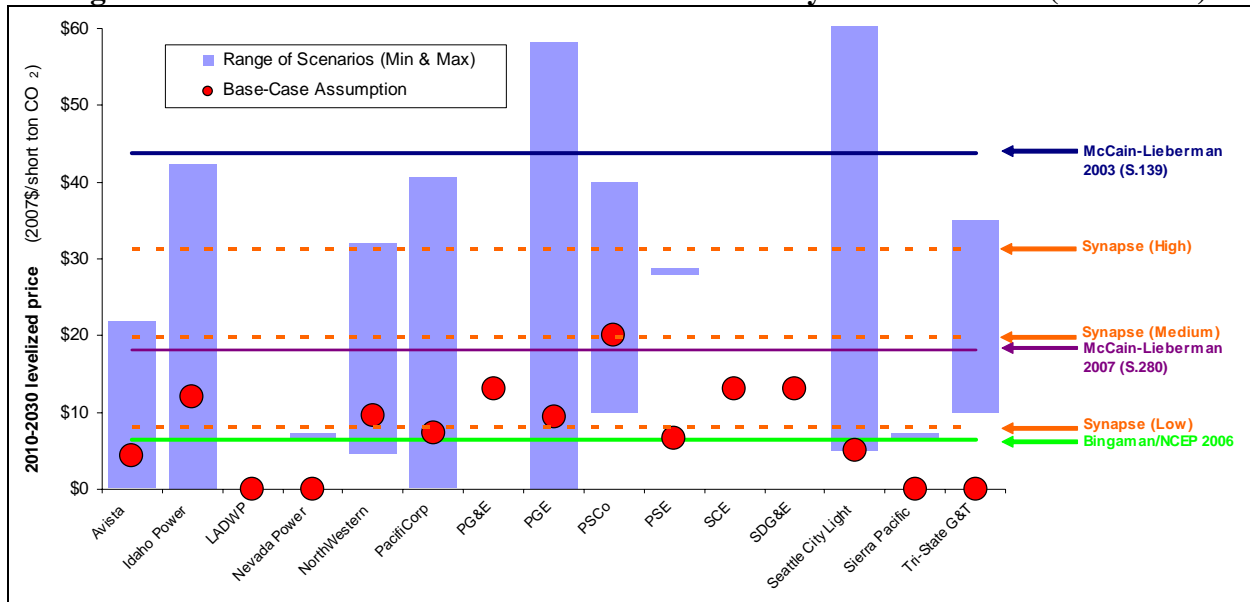
Eleven of the fifteen utilities in our sample included carbon regulatory costs in their base-case portfolio analysis, with levelized carbon emission price projections ranging from \$4 to \$20 per short ton of CO₂ (2007\$). As shown in Figure 1, most utilities' base-case carbon price assumptions are near the low end relative to the benchmarks provided in the figure. It would therefore appear that many utilities – particularly those with no carbon regulation in their base-case analysis – may be underestimating the “most likely” cost of carbon emissions, especially given that NCEP now recommends a higher safety-valve price than in its original proposal, which many utilities used as the basis for their base-case carbon price projection.²

Given the inherently speculative nature of projecting future policy outcomes and the resulting allowance prices, it is particularly important for resource planners to model candidate portfolio costs under a broad range of carbon emission prices. Eleven of the utilities in our

² The “safety-valve” is a cap on allowance prices. NCEP originally recommended a safety-valve price of \$7 per metric ton CO₂-equivalent in 2010, escalating at 5% per year in *nominal* dollars (NCEP 2004). NCEP revised its recommendations in 2007, suggesting an initial safety-valve price of \$10 per metric ton CO₂-equivalent in 2012, escalating at 5% per year in *real* dollars (NCEP 2007).

review conducted scenario analyses to evaluate portfolio costs under alternate carbon price projections to their base-case, including three of the four utilities that assumed no carbon regulations in their base-case. Most of these eleven utilities evaluated scenarios with levelized carbon prices of \$30/ton or greater, which is consistent with a relatively aggressive carbon policy. However, several utilities (Avista, Nevada Power, and Sierra Pacific) examined a more-limited range of carbon price scenarios, and four utilities (LADWP, PG&E, SCE, and SDG&E) examined no alternate carbon price scenarios. Consequently, the portfolio analysis used by these utilities afforded limited opportunity to assess the exposure of candidate portfolios to carbon regulatory risk.

Figure 1. Levelized CO2 Emission Prices Used in Utility Resource Plans (2010-2030)



Other Types of Carbon Regulations Considered

Future carbon regulations could take various forms other than a carbon tax or cap-and-trade system. As described previously, a number of Western states have already adopted generation carbon emission performance standards (California, Montana, and Washington) and/or carbon emission mitigation requirements (Montana, Oregon, and Washington). Utilities in states with existing emission performance standards and/or mitigation requirements all accounted for these regulations within their resource plans, provided that the regulations were in place at the time that the resource plan was prepared. In addition, several utilities considered expansions to existing state carbon regulations. Specifically, PacifiCorp considered a scenario in which an emission performance standard similar to the one already adopted in California and Washington is implemented throughout the utility's six-state service territory. PGE, meanwhile, assumed that Oregon's existing carbon emission mitigation standard for new baseload power plants would apply to coal-fired baseload generation (not just natural gas-fired generation, as is currently the case). However, beyond these examples, no utilities considered potential carbon policies, at either the state or federal level, other than a carbon tax or cap-and-trade.

Evaluation of Energy Efficiency as a Hedge against Carbon Regulatory Risk

Another critical aspect of managing carbon regulatory risks is to evaluate options for hedging exposure to those risks. At present, the primary means by which U.S. utilities can hedge carbon regulatory risks is by focusing future resource development on low-carbon resources, including energy efficiency. Standard practice in utility resource planning is to construct multiple candidate resource portfolios, each composed of different types and quantities of various resource options. Utilities then estimate the cost of each candidate portfolio under a range of alternate assumptions about future conditions, in order to reach a decision about a single “preferred” resource strategy. A utility’s ability to fully assess the cost and value of mitigating its exposure to carbon regulation risk is therefore contingent upon its consideration of sufficient quantities of low-carbon resources.

In this section, we examine the extent to which utilities considered energy efficiency as an option for hedging their exposure to carbon regulatory risk. We distinguish between two underlying issues: (1) the amount of energy efficiency considered, and (2) the manner in which utilities evaluated the value of energy efficiency related to avoided carbon costs and risks.

For some utilities, the amount of energy efficiency considered, and the manner in which it is incorporated into the overall portfolio analysis, reflects existing laws and regulations. At the most basic level, most Western state PUCs have adopted resource planning rules that require utilities to evaluate energy efficiency on an “equivalent” or “comparable” basis to conventional supply side options. Several states have adopted more prescriptive and aggressive policies. For example, Washington requires its utilities to acquire all cost-effective energy efficiency, and California’s “loading order” policy requires investor-owned utilities to acquire all cost-effective energy efficiency and renewable generation before investing in traditional supply-side options. Additionally, energy efficiency portfolio standards (as in Colorado) and long-term energy efficiency goals (as in California) set floors on the amount of energy efficiency that utilities include in their resource plan.

Maximum Energy Efficiency Resource Levels Considered

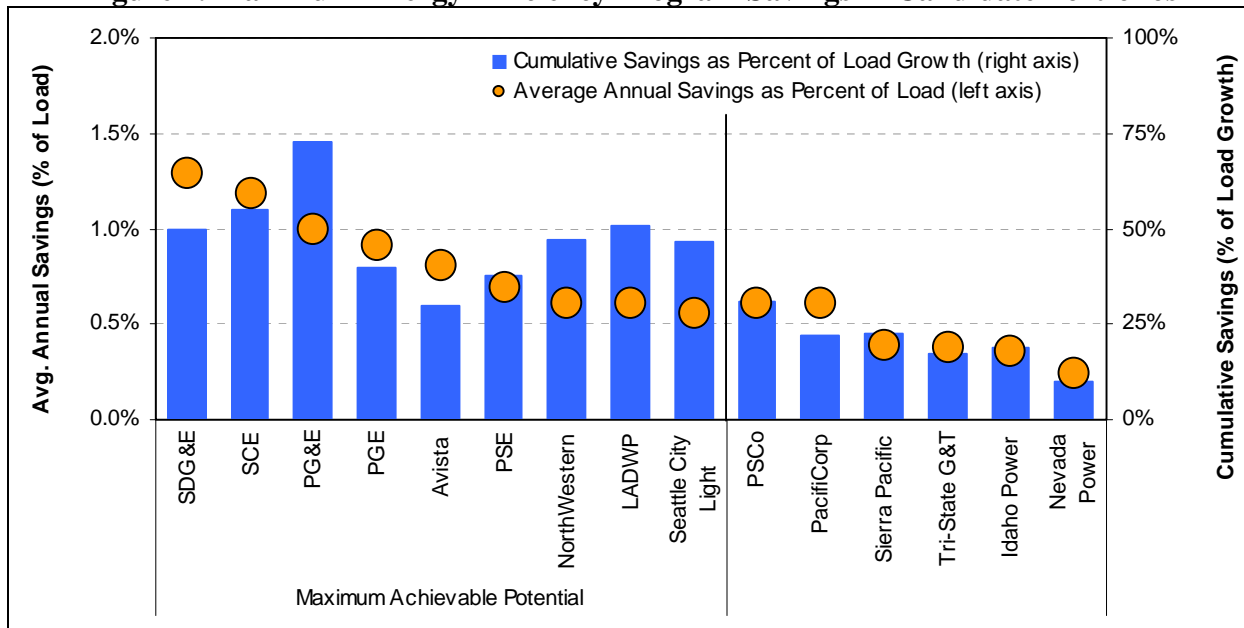
All fifteen utilities included future energy efficiency programs in at least some of their candidate resource portfolios (see Table 2). Nine utilities (Avista, LADWP, NorthWestern, PGE, PG&E, PSE, SCE, SDG&E, and Seattle City Light) report that they included the “maximum achievable” energy efficiency potential in all candidate portfolios.³ The other six utilities, with the possible exception of PacifiCorp, imposed what are effectively non-economic caps on the quantity of energy efficiency considered in their resource plan – by examining either only a sub-set of cost-effective measures and/or programs funded at less than 100% of incremental measure cost. Notwithstanding the fact that these six utilities may not have considered acquiring all cost-effective, achievable energy efficiency savings opportunities, all evaluated energy efficiency savings targets well above historical levels.

Figure 2 shows the maximum amount of future energy efficiency that each utility

³ The maximum achievable potential is the portion of the total cost-effective potential that could be achieved over a given time-span, assuming that the utility funds 100% of the incremental cost of more-efficient equipment, and taking into account naturally-occurring customer investment in energy efficiency as well as practical constraints to increasing adoption rates (e.g., stock turnover rates and non-economic market barriers) [Rufo & Coito 2002; National Action Plan for Energy Efficiency 2007].

included in its candidate portfolios. We segment the utilities according to whether or not their target is based on the maximum achievable potential. We express energy efficiency targets in terms of two metrics: (1) the average annual incremental savings as a percent of total retail load and (2) the cumulative savings over the planning period as a percent of projected retail load growth (absent future utility-funded energy efficiency programs).⁴

Figure 2. Maximum Energy Efficiency Program Savings in Candidate Portfolios



The nine utilities on the left-hand side of the figure included in *all* candidate portfolios evaluated their estimate of the “maximum achievable” energy efficiency program savings. Three of these utilities (PG&E, SCE, and PSE) evaluated candidate portfolios with different estimates of the maximum achievable potential, based on alternate underlying assumptions (e.g., regarding avoided costs). The energy efficiency levels evaluated in these utilities’ candidate portfolios ranged, in terms of *average annual savings*, from 0.6% to 1.3% of total retail load, and in terms of *cumulative savings* over the planning period, from 30% to 73% of projected load growth. This range in values may reflect myriad factors, including differences across utilities in climate, end-use saturations, state building and appliance codes, load growth, and avoided supply-side resources, as well as potentially different methodologies used to estimate maximum achievable potential. The other six utilities did not evaluate candidate portfolios with the maximum achievable energy efficiency potential. Not surprisingly, the maximum level of energy efficiency in these utilities’ candidate portfolios was notably less, with average annual savings ranging from 0.2% to 0.6% of total retail load, and cumulative savings ranging from 10% to 31% of projected load growth.

⁴ These values represent estimated energy savings from utility-funded energy efficiency programs considered for implementation over the planning period, but not savings associated with utility programs implemented prior to the planning period, energy efficiency codes and standards, or “naturally-occurring” energy efficiency adoption.

Evaluating the Avoided Carbon Regulation Costs and Risk from Energy Efficiency

In general, carbon regulations improve the cost-effectiveness of energy efficiency, and at higher carbon prices, greater levels of energy efficiency are cost-effective. Twelve of the fifteen utilities developed their energy efficiency targets through some assessment of cost-effectiveness.⁵ Most of the twelve utilities that performed a cost-effectiveness assessment appear to have used their base-case carbon price projection when estimating avoided costs. The only possible exceptions are PGE and Seattle City Light, whose plans do not provide any indication of whether carbon prices were incorporated into the cost-effectiveness analysis, and LADWP, which did not include carbon emission costs in any element its resource planning analysis.

However, to assess the value of energy efficiency in mitigating carbon regulatory risk, as opposed to simply reducing expected carbon emission costs, utilities may need to evaluate energy efficiency cost-effectiveness and market potential across a range of future carbon price projections. Only one utility, PSE, included such a sensitivity analysis *within its resource plan*.⁶ PSE developed five distinct estimates of the maximum achievable energy efficiency potential, each based on a different projection of avoided costs incorporating either its base-case or an alternate carbon price assumption. The utility selected three of these energy efficiency targets to group with eight supply-side candidate portfolios, yielding a total of 24 integrated demand- and supply-side candidate portfolios, which it then evaluated through a series of stochastic and deterministic analyses. This approach allowed the utility to assess whether additional energy efficiency, beyond what is cost-effective under base-case carbon price assumptions, might nevertheless be justified in light of the incremental net savings anticipated under higher carbon prices.

Accounting for Indirect Impacts of Carbon Regulations

Within the context of utility resource planning, the most direct effect of future carbon regulations would be to increase the operating cost of carbon-emitting resources in the utility's candidate portfolios. There are, however, a multitude of potential indirect impacts of carbon regulations that may also be important for utilities to incorporate into their resource planning analysis. In this section, we briefly describe a number of these potential indirect effects, focusing on those that are most relevant to energy efficiency – namely, the effects on regional electricity market prices, natural gas prices, and load growth. As we discuss below, utility resource planners are only beginning to acknowledge and evaluate many of these potentially significant effects, suggesting that some additional effort may be needed to assess how best to incorporate these effects in energy planning and investment decisions.

⁵ The exceptions are Nevada Power and Sierra Pacific, whose candidate portfolios all include the maximum amount of energy efficiency that can qualify for the state's renewable portfolio standard, and Tri-State, which considered only a set of specific programs that passed several qualitative screens.

⁶ Energy efficiency targets evaluated in utilities' resource plans are often based on market potential studies. It is possible that, in estimating economic potential, some market potential studies may have considered the value of energy efficiency in reducing carbon regulatory risk (e.g., based on a sensitivity analyses around future carbon emission costs or by imposing a proxy, risk-reduction adder/multiplier). However, utilities' resource plans generally provide few details about the specific assumptions and methods used in underlying energy efficiency market potential studies; thus, we are unable to conclude, simply from a review of utilities' resource plans, whether the energy efficiency targets evaluated in the plans reflect consideration of the value of energy efficiency as a hedge against uncertain future carbon emission costs.

Electricity Market Prices

Analyses of carbon policy proposals typically project that carbon regulations would lead to an increase in wholesale electricity market prices. Capturing this effect is critical to properly valuing energy efficiency cost-effectiveness and market potential, given that wholesale electricity market prices are typically a key input to deriving avoided costs. Impacts on wholesale electricity prices are also important to account for in resource planning, because different candidate portfolios generally have different levels of exposure to wholesale market prices; ignoring the effect of carbon regulations on regional electricity market prices could therefore create a bias toward portfolios with a heavier reliance on market purchases.

Carbon regulations could impact regional electricity market prices through a variety of mechanisms, the most immediate being to add an emission cost to the marginal cost of generators throughout the region, thereby raising market prices. A utility's ability to account for this particular effect depends on how it develops its electricity price forecast. Most of the Pacific Northwest utilities in our sample (Avista, Idaho Power, PacifiCorp, PGE, and PSE) used regional production cost models to develop electricity market price forecasts for each scenario evaluated in their plans, and used the corresponding carbon price projection as an input to the simulation model for each scenario. Alternatively, PSCo and NorthWestern developed their electricity price forecasts from projections of marginal heat rates for nearby trading hubs, which they translated into electricity price projections based on fuel price and carbon price forecasts. This approach also captures the impact of carbon prices on electricity market prices, but is somewhat cruder than the production cost model approach, as it does not account for potential changes in regional dispatch order due to differing marginal carbon emission rates of generation resources in the region. The effect of carbon regulations on dispatch order could be particularly important at carbon prices high enough to raise the operating cost of pulverized coal-fired generation above that of a CCGT.

The remaining utilities (Nevada Power, PG&E, SCE, SDG&E, Sierra Pacific, and Tri-State) do not appear to have accounted for the impact of carbon regulations on wholesale electricity market prices. However, the three California investor-owned utilities did include a carbon adder when calculating the cost-effectiveness of energy efficiency and renewable resources, which is functionally similar.

Natural Gas Commodity Prices

Natural gas demand, and thus natural gas commodity prices, could increase or decrease under carbon regulations, depending on the relative cost and availability of alternatives to conventional coal-fired generation. Any resulting change in natural gas prices would affect the expected cost of natural gas-fired generation evaluated within a utility's candidate portfolios as well as electricity market prices, to the extent that gas-fired generation is the marginal generation resource in the region. These impacts could conceivably be of the same order of magnitude as the direct emission costs associated with carbon regulations. From the perspective of energy efficiency, these effects are most important because of the associated impact on avoided costs.

All utilities in our sample evaluated candidate portfolio costs under multiple gas price forecasts; however, only four utilities explicitly linked gas prices and carbon prices for the purposes of developing electricity market price projections and modeling the cost of candidate

portfolios. Three of these utilities (PSCo, PSE, and Seattle City Light) simply used their “high gas price” forecasts in their “high carbon price” scenario, although their high gas price projections were not developed based on any specific assumptions about future carbon emission prices. PacifiCorp, in contrast, commissioned an outside consultant to develop separate natural gas price forecasts specific to each of its carbon tax and cap-and-trade scenarios. None of the other utilities made any systematic link between their carbon price and natural gas price assumptions.

Load Growth

Rising retail electricity prices resulting from carbon regulations could reduce load growth (apart from the effects of energy efficiency program activity). Although virtually all of the utilities in our sample developed low load growth projections, only two utilities (PSE and PSCo) explicitly linked high carbon prices to low load growth within their analysis, although in neither case was it apparent that these load growth projections were incorporated into their estimates of energy efficiency market potential under high carbon prices. Capturing the potential effect of carbon regulations on *regional* load growth may also be important for assessing the potential role of energy efficiency, given the corresponding effect on electricity market prices and hence avoided costs. Three utilities (Avista, PSE, and Seattle City Light) accounted for this potential dynamic, by assuming reduced load growth throughout the region within their simulation models used to develop electricity price projections for carbon regulation scenarios.

Other Indirect Impacts

In addition to the effects highlighted above, carbon regulations could affect regional energy markets in a number of other ways that may be important for energy planners to consider. These include potential impacts on:

- **Allowance prices for other capped air pollutants**, resulting from a reduction in traditional coal-fired power generation and correspondingly reduced demand and prices for criteria air pollutant (e.g., SO₂) emission allowances;
- **Coal-plant retirements**, as carbon emission costs decrease the number of hours that existing coal-plants can economically operate, potentially leading to changes in regional electricity prices and new capacity needs;
- **Regional generation expansion**, as utilities shift their capacity expansion efforts towards low-carbon generation, which could, in turn, affect electricity market prices;
- **Regional transmission expansion**, as utilities construct new transmission into regions rich in low-carbon resources, which could enable broader access to these resources by other utilities;
- **Availability of federal incentives**, if legislators viewed existing financial incentives for low-carbon resources as duplicative, possibly resulting in an accelerated reduction or discontinuation of those incentives;
- **Capital costs and technology development** associated with rapidly increasing demand for commercially-available low-carbon resources (e.g., wind) and/or accelerated “learning curve” effects for emerging low-carbon resources (e.g., concentrating solar or carbon capture and sequestration).

The Contribution of Energy Efficiency to Utilities' Preferred Resource Portfolios

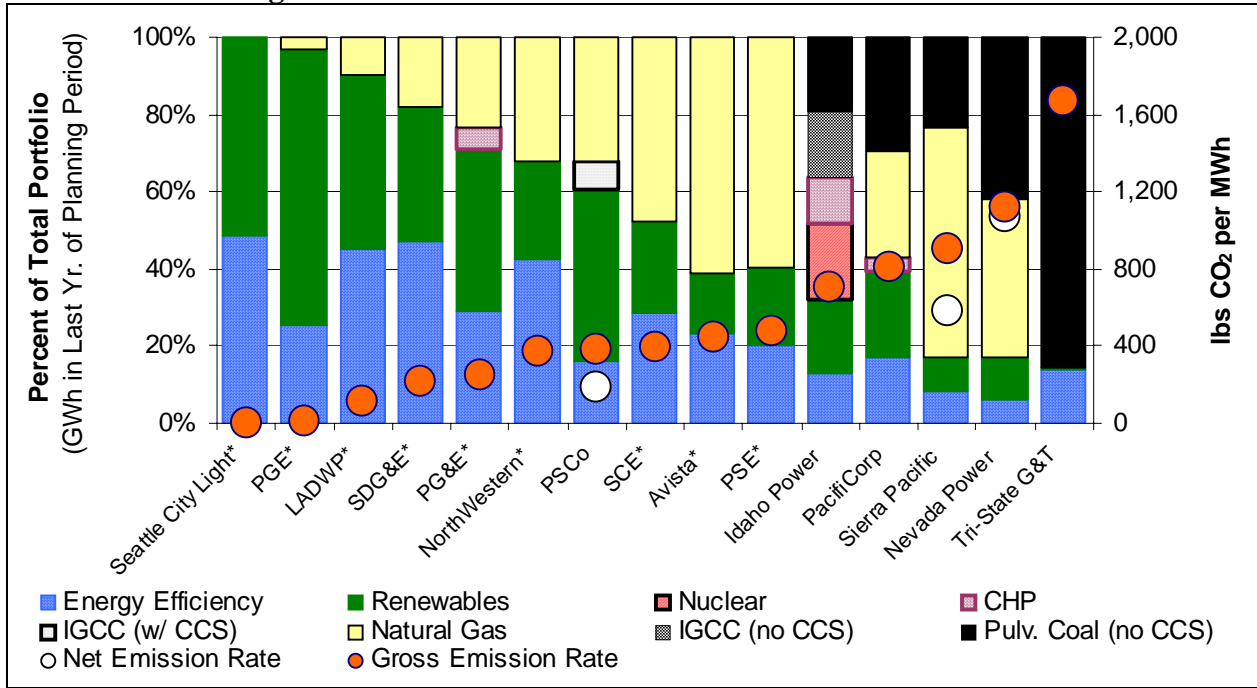
Though generally not a binding, long-term commitment, the preferred resource portfolios identified in utility resource plans nevertheless provide perhaps the best public indication of their current long-term resource strategies. In this section, we summarize the preferred portfolios selected by the fifteen utilities in our sample, in order to highlight general trends and differences in the strategic direction of Western utilities and the projected role of energy efficiency.

Figure 3 describes the composition and carbon intensity of the utilities' preferred portfolios, based on the expected energy generation (or savings, in the case of energy efficiency) in the last year of each utility's portfolio construction period (as identified previously in Table 1). We exclude from the figure: existing generation, new generation already under development/contract at the time of the resource plan, future contract renewals, and future short- and medium-term market purchases not tied to a specific resource. Thus, Figure 3 focuses specifically on new, physical supply- and demand-side resources in each utility's preferred portfolio. The utilities are ordered along the x-axis according to the average carbon emission rate of new resources in the portfolio portfolios, weighted based on the expected energy generation/savings of each resource type.

As Figure 3 shows, all utilities included future energy efficiency programs in their preferred portfolio, but the relative contribution differs quite widely across utilities. For example, four utilities (Seattle City Light, LADWP, SDG&E, and NorthWestern) selected preferred portfolios in which energy efficiency constitutes 40% or more of the total portfolio energy resources. At the other end of the spectrum, the two Nevada utilities selected portfolios in which energy efficiency makes up less than 10% of the total. To some extent, these differences may simply reflect the varying size of utilities' incremental resource needs relative their total customer load, as well as characteristics of their customer base. However, the percentage contribution of energy efficiency to utilities' preferred portfolios is also clearly a function of how they developed their targets. In particular, the preferred portfolios with the greatest contribution from energy efficiency belong to those nine utilities that included the maximum achievable potential in all of their candidate portfolios (and thus also in their preferred portfolio), as designated by an asterisk (*) in Figure 3. Furthermore, we can see that the percentage contribution from energy efficiency, along with renewables, is the driving factor in the overall carbon intensity of the preferred portfolios.

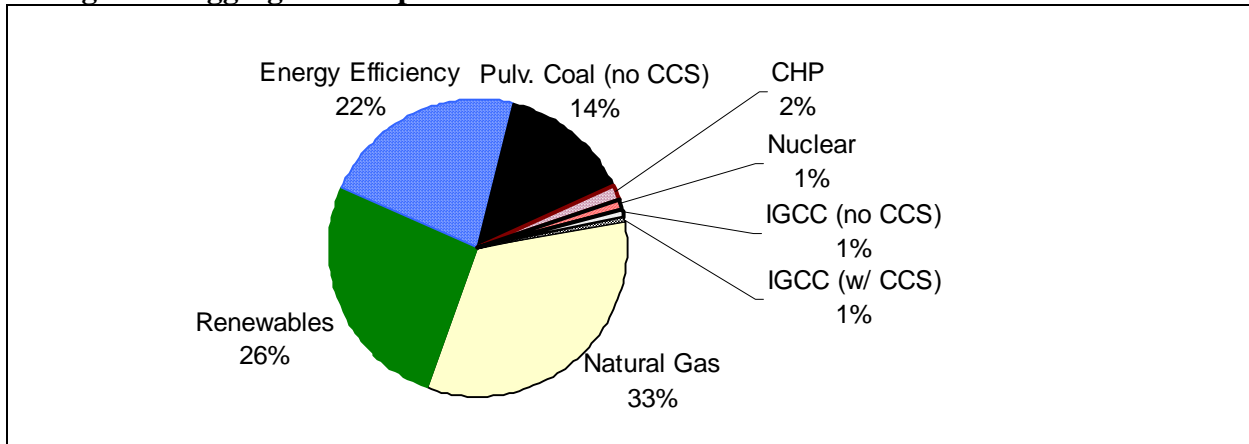
Adding up the new resources in the preferred resource portfolios selected by the utilities in our sample provide a picture, albeit partial and provisional, of electric resource development in the West over the next ten to twenty years, and the relative role of energy efficiency (see Figure 4). In aggregate, natural gas-fired generation is the largest component (33%) of all incremental energy resources in the utilities' preferred portfolios. Renewables (26%), energy efficiency (22%), and pulverized coal (14%) make up the lion's share of the remaining new resources, with small contributions from CHP (2%), nuclear (1%), IGCC with CCS (1%), and IGCC without CCS (1%).

Figure 3. New Resources in Utilities' Preferred Portfolios



Notes: Gross emission rate refers to the composite emission rate of all new supply- and demand-side resources. Net emission rate also accounts for emission reductions associated with planned retirements over the planning period. Utilities that included the maximum achievable energy efficiency potential in their preferred portfolios are designated by an asterisk (*) after their name.

Figure 4. Aggregate Composition of Western Utilities' Preferred Resource Portfolios



Conclusions and Recommendations

Future carbon regulations could require a dramatic shift in electric infrastructure development away from conventional fossil generation technologies, and an unprecedented scale-up of investment in low-carbon resources. Long-term resource planning can serve an instrumental role in facilitating this possible shift, by providing a framework for analyzing the potential cost and risks associated with future carbon regulations and by assessing options for

mitigating that risk. For utility resource planning to serve this role effectively, however, requires confidence that the specific assumptions and methods used to analyze carbon regulatory risk are sound and will support prudent investment decisions.

Our review of recent Western utility resource plans has shown that utilities are making important strides in accounting for the financial risks associated with future carbon regulations. At the same time, their assumptions and methods vary considerably, and reveal opportunities for improvement. Energy regulators have a particularly important role in ensuring that carbon risk is appropriately addressed, given their responsibility to ensure prudent investment decisions by regulated utilities, and given that much of the costs of future carbon regulations will ultimately be born by ratepayers. State regulators and policy-makers should therefore consider providing policy guidance to utilities on appropriate assumptions and methods to be used in assessing and managing these risks in their long-term resource plans.

Based on our review of current planning efforts in the Western U.S., we offer the following recommendations for ensuring that energy efficiency is fully valued as a hedge against carbon regulatory risks:

- Include a projection of carbon costs in the base-case that reflects an estimate of the most-likely carbon regulations to occur over the planning period.
- Develop alternative carbon price scenarios that encompass the range of plausible carbon policies over the planning period.
- Evaluate candidate portfolios with the maximum achievable energy efficiency potential.
- Evaluate energy efficiency cost-effectiveness and market potential across the full range of carbon price scenarios considered in the resource plan.
- When evaluating energy efficiency cost-effectiveness, account for the potentially significant indirect impacts of future carbon regulations, particularly the effects on wholesale electricity market prices, natural gas prices, and load growth.

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