

ATTACHMENT 1

Survey of Utility Resource Planning and Procurement Practices for Application to Long-Term Procurement Planning in California

FINAL

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1 Introduction

This report presents the results of a survey of electric utility resource planning and procurement practices in a number of jurisdictions across North America. The purpose of the survey is to establish a common understanding of the processes and approaches used in long-term planning and procurement by electric utilities in North America to help guide parties' participation in the California Public Utilities Commission's ("CPUC") 2008 and 2010 Long-Term Procurement Plan ("LTPP") proceedings. While California utilities have not undertaken a full integrated resource planning effort in many years, the 2008 LTPP proceeding is considering the appropriate role of utility resource planning in procuring the resources needed to meet state policy goals. This survey aims to seed that process with information about practices in other jurisdictions so that parties can evaluate whether and to what extent these practices are appropriate and useful in the current California context.

The survey finds that long-term resource planning practices vary by jurisdiction according to retail market structure. States that have not deregulated their retail markets, i.e., that continue to regulate the provision of bundled retail electric service by vertically-integrated utilities, have returned to resource planning over the last several years as the momentum toward industry restructuring has slowed. A wide variety of practices is exhibited in these jurisdictions, but the common element is a long-term plan that selects a preferred resource portfolio based on its superior performance in minimizing cost and risk to retail ratepayers, while satisfying regulatory mandates such as energy efficiency and renewable energy targets.

In deregulated jurisdictions, energy procurement is almost uniformly conducted exclusively via market mechanisms, and utilities for the most part no longer engage in long-term resource planning.¹ Even in deregulated jurisdictions, however, there is an emerging trend of re-introducing longer-term planning and procurement, due in part to state policies that promote the development of renewable and/or low-carbon resources and the associated need for new transmission infrastructure. For example, some states have recently begun to allow longer-term contracting for renewable resources. Further, some states have begun to reconsider whether to allow longer-term contracting and even utility ownership of conventional generating resources due to concerns over recent rapid increases in retail rates.

Just as it led the charge toward deregulation in the 1990s, California is now at the forefront of efforts to increase the use of renewable energy and reduce greenhouse gas emissions. Adoption of a 33 percent renewables portfolio standard ("RPS") would give California the most aggressive RPS in the nation, while the passage of California's Global Warming Solutions Act makes California one of the first states to mandate reductions in greenhouse gas emissions. Meeting California's 2020 policy goals will, under a variety of plausible scenarios, require substantially higher levels of investments in new generation and transmission infrastructure over the next twelve years than any comparable historical time period.

¹ Throughout this report, we refer to "regulated" and "deregulated" markets to distinguish jurisdictions in which vertically-integrated utilities continue to provide bundled service under state regulation from those that have restructured their retail markets in one form or another for the purpose of introducing retail competition and customer choice. We recognize that regulation continues in many forms even in "deregulated" markets. While some comments on the draft version of this report suggested instead using the terms "non-restructured" and "restructured" markets, we find "regulated" and "deregulated" to be less cumbersome and more suitable for our purposes.

California's energy procurement processes that rely on all-source Requests for Offer ("RFOs") still resemble those of the deregulated jurisdictions more than the regulated jurisdictions. However, California has already crossed the bridge of allowing long-term contracting for new renewable resources, and the CPUC has recently allowed utilities to purchase and develop conventional power plants. The CPUC is considering in this docket whether California's current planning and procurement processes are suitable for procuring the massive quantities of new resources required to meet its aggressive policy goals. This survey is intended to provide information about energy planning and procurement practices in other jurisdictions to inform this discussion.

This report is organized into four chapters. Chapter 1 provides an overview of resource planning in regulated and deregulated jurisdictions. Chapter 2 describes California's current market structure and discusses the regulatory and policy drivers influencing resource planning in the state. Chapter 3 describes procurement practices in other deregulated jurisdictions. Chapter 4 surveys resource planning in regulated jurisdictions and compares these practices to the California utilities' 2006 LTPPs.

1.1 Overview of Resource Planning and Procurement

Resource planning and procurement activities in North American jurisdictions fall into two categories based on market organization. In *regulated* jurisdictions, vertically-integrated utilities continue to provide bundled service — generation, transmission and distribution service under bundled retail rate structures — to retail electricity customers under regulation by state regulatory commissions or local governing boards. In *deregulated* jurisdictions, retail electric service has been "unbundled" into separate generation, transmission and distribution components, with the generation component under retail access provided by competitive electric service providers ("ESPs"). The traditional utility continues to provide distribution service and may also be called upon to provide "default", "standard offer" or "last resort" generation service to retail customers that are not served by a competitive supplier.

As might be expected, resource planning and procurement activities vary considerably for these two types of jurisdictions. In regulated jurisdictions, utilities engage in a myriad of long-term planning efforts, from forecasting future load and determining the need for new resources through selecting the types of resources that make up a “preferred portfolio”. The result of this planning process is a utility plan to build or acquire new generating or demand-side resources to serve bundled loads. This plan is typically informed by a stakeholder process and then filed with the state regulators, who rule on the prudence of utility investments and decide which costs are allowed to be collected through retail rates.

In deregulated jurisdictions, by contrast, utility procurement activities are typically limited to competitively procuring relatively short-term (1-3 year) contracts that also offer a hedge against volatile spot market prices. This reflects the commonly stated policy goals of electricity market restructuring: (1) to facilitate customer choice via direct retail access, (2) to affect economic efficiency via generation market competition, and (3) to a lesser extent, to shift the risk of investments in new generation resources from ratepayers to investors. Some of the planning functions have moved from state-regulated utilities to Independent System Operators (“ISOs”) or Regional Transmission Organizations (“RTOs”) regulated by the Federal Energy Regulatory Commission (“FERC”). Others are now performed by unregulated wholesale energy market participants. Some planning functions may not be performed at all. Indeed, the move toward restructured markets was intended to reduce the influence of centralized resource planning and acquisition.

1.2 Key Functions of Resource Planning

At a high level, utility resource planning and procurement seeks to determine: (1) the quantity of new resources that are required for reliable electric service; (2) which resources to acquire based on attributes such as cost, risk and environmental impact; and (3) when and how to acquire them. Figure 1 below depicts the key activities that

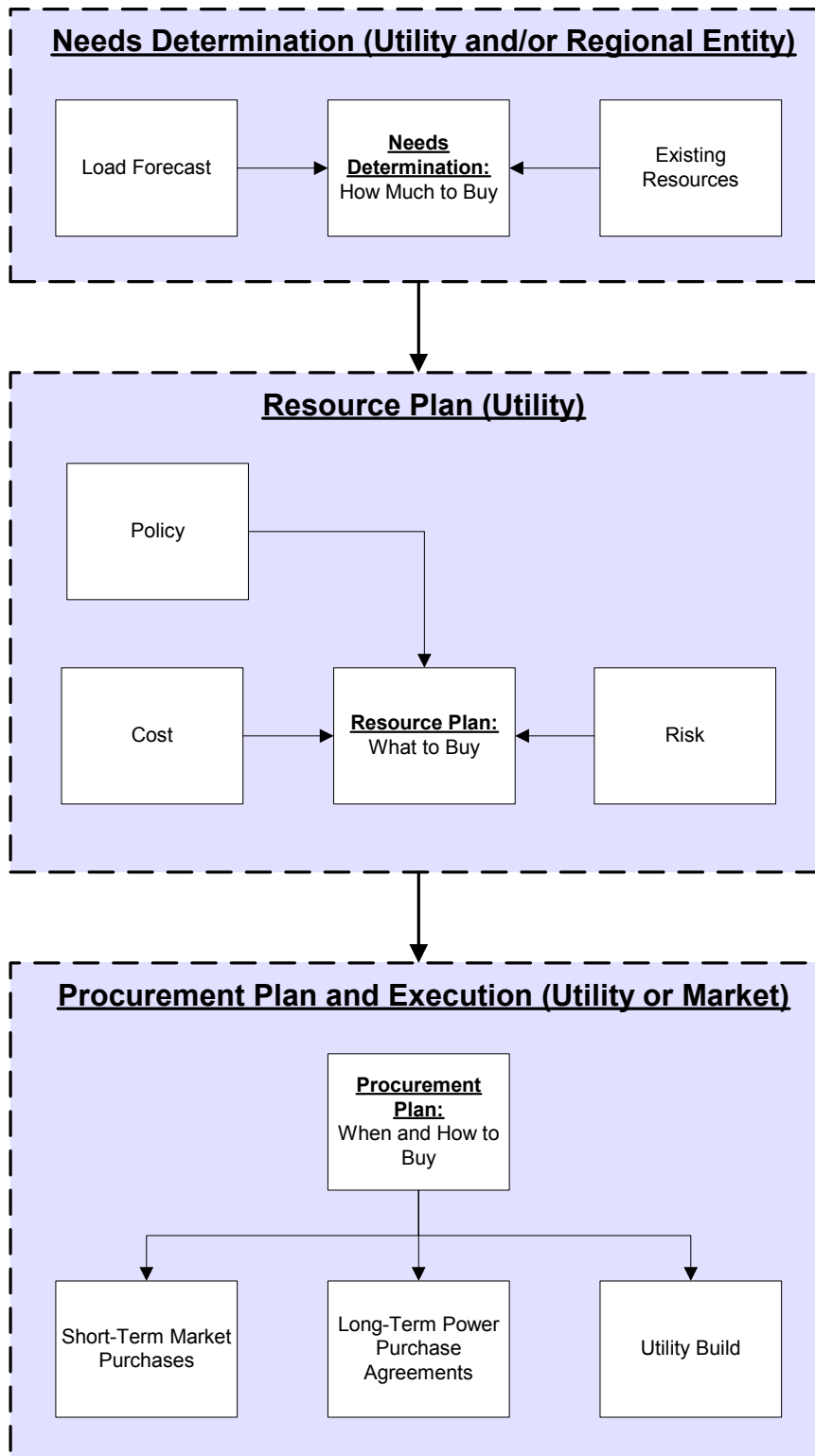
characterize the resource planning effort. The diagram is divided into three sections to reflect these three key functions: (1) Needs Determination; (2) Resource Planning; and, (3) Procurement Planning.

The “Needs Determination” step calculates the quantity of new resources required for reliable load service during the planning horizon. Depending on the jurisdiction, this step may be done by a utility or by a regional entity such as an RTO (e.g., PJM Interconnection) or a Regional Reliability Council (e.g., the Western Electricity Coordinating Council (“WECC”)). Needs Determination entails forecasting both future loads and the capability of existing resources to serve those loads. This process frequently produces “Load and Resource” tables that are used to illustrate need over time. This process does not necessarily differ for regulated and deregulated jurisdictions, particularly when it is conducted or overseen by a regional entity, although a utility in a deregulated jurisdiction will need to account for the possibility of customer switching between utility and competitive service.

Once future needs are understood, a utility in a regulated jurisdiction may engage in “Resource Planning” in which it develops and tests resource portfolios representing different potential mixes of resources with which those needs can be met. This requires an understanding of the cost and performance characteristics of both existing and new resources. Utilities are frequently concerned about portfolio *risk* in addition to cost, so portfolios are typically considered under alternative forecasts for such items as demand, cost, and resource availability.

Modeling software is typically used to integrate these pieces and calculate quantitative metrics – such as utility cost or average rates – by which the performance of alternative portfolios are measured. Also, the environmental impact of alternative portfolios can be measured in terms of the plans’ impact on land, air, or water. Finally, policy constraints such as RPS or more recently, GHG emissions, can be treated as constraints on the portfolio development process.

In deregulated jurisdictions, utilities do not typically make long-term generation investments that enter the utility's rate base. Generating resources are financed and developed by competitive, profit-maximizing generation suppliers in response to market signals. Thus, most deregulated utilities do not engage in formal Resource Planning processes. Instead, they develop processes that aim to minimize the costs of short-term, market-based procurement. State regulation is typically limited to ensuring that the procurement process results in supply bids that are workably competitive and reflect prevailing market prices.

Figure 1: Key elements of utility resource planning

Once the utility has determined its resource needs, it needs to decide how to procure the resources. The “Procurement Plan” details utility plans to construct resources as well as the form and timing of efforts to solicit market-based supply offers. In regulated jurisdictions, utilities may request short-term or long-term offers from competitive generation suppliers, and may compare bids received against their expected cost of constructing the resources themselves. In deregulated jurisdictions, utilities are generally restricted to market-based procurement over a shorter term.

1.3 The Effect of Policy Requirements on Utility Planning and Procurement Processes

The previous section describes the processes of determining the appropriate mix of resources to acquire to serve retail load in both regulated and deregulated jurisdictions. In regulated jurisdictions, utilities develop resource plans that weigh the cost, risk and operating characteristics of a variety of resource types against each other and select a “preferred portfolio.” In deregulated jurisdictions, competitive suppliers construct resources in response to market signals. However, many states have enacted statutes or established policy goals that aim to affect the mix or type of resources used for retail load service. For example, many states have enacted renewables portfolio standards that require load-serving entities (“LSEs”), including both utilities and competitive suppliers to serve a given proportion of retail load with qualifying renewable resources. Other states have established goals for procurement of energy efficiency or for reducing greenhouse gas emissions. The effect of these state policy goals on resource planning and procurement differs for regulated and deregulated jurisdictions.

In regulated jurisdictions, utilities may treat state policy as a constraint in developing portfolios. That is, each candidate portfolio must have sufficient energy efficiency, renewable resources, etc. to meet the state requirements. The utilities then plan the best mix of resources to meet the remaining need. State policy goals are thereby directly reflected in the utilities’ resource acquisition plans. Moreover, the utility’s ability to

engage in long-term procurement either through the “self-build” option or by signing long-term contracts with suppliers provides the financing certainty necessary to bring about the desired resource mix with a relatively high degree of certainty.

Many deregulated states have also enacted policy goals such as renewables portfolio standards that typically apply to competitive retail service providers as well as to utility service. However, there is some evidence that the lack of long-term planning and procurement activities hampers the ability of LSEs to meet state RPS goals. Renewable resources are capital-intensive and generally have higher delivered cost of energy than conventional resources such as gas-fired combustion turbines. Investors have been reluctant to support renewable resource development without some certainty of cost recovery over the long-term. As a result, some states have recently taken steps to allow utilities to engage in longer-term procurement activities for the express purpose of RPS compliance. While utility planning for GHG reduction is still in its infancy, increased interest in reducing greenhouse gas emissions is likely to intensify this trend toward long-term planning and procurement for RPS compliance in deregulated jurisdictions.

In addition to state RPS and GHG policy, federal policy also promotes long-term planning and procurement. As part of its Order No. 890 Guidelines, FERC has encouraged transmission providers to begin developing long-term transmission plans to ensure that beneficial transmission infrastructure is constructed to foster efficient generation development. While RTOs do not own and operate new generation, long-term transmission planning requires some assumptions about the type and location of new generation development, and some RTOs have therefore begun to develop indicative long-term resource plans for their service areas – see section 3.5 below. In addition, markets for capacity services have been introduced to ensure that sufficient generating resources are constructed to maintain reliable service to retail loads. While these capacity services are competitively provided, capacity in many areas can be provided either by generation or transmission, and the interaction between forward

capacity markets and RTO transmission plans is therefore coming under increased scrutiny.

Finally, simply having a competitive procurement process is proving insufficient in some regions for achieving the goal of clean, safe and reliable service at reasonable and stable rates to all retail customers, irrespective of state policy with respect to resource types.² Even if the generation markets are workably competitive, achieving this goal has been difficult because merchant generation investments, whether conventional or renewable, are not occurring without long-term contracts signed with LSEs that provide a sufficient long-term revenue stream.³ The use of long-term contracts to finance renewable energy development necessitates portfolio management and long-term planning.⁴ Indeed, restructured states such as Montana, Maryland, New Jersey, and New York are now considering increased use of long-term planning to determine how to best obtain power supply for their regulated utilities.⁵

² Woo, C.K., D. Lloyd and W. Clayton (2006) "Did a Local Distribution Company Procure Prudently during the California Electricity Crisis?" *Energy Policy*, 34:16, 2552-2565.

³ Woo, C.K., M. King, A. Tishler and L.C.H. Chow (2006) "Costs of Electricity Deregulation," *Energy*, 31:6-7, 747-768.

⁴ Biewald, et al (2003) *Portfolio Management: How to Procure Electricity Resources to Provide Reliable, Low-Cost, and Efficient Retail Customers*, Synapse Energy Report to The Regulatory Assistance Project and The Energy Foundation, www.synapse-energy.com; Woo, C.K., I. Horowitz, A. Olson, B. Horii and C. Baskette (2006) "Efficient Frontiers for Electricity Procurement by an LDC with Multiple Purchase Options," *OMEGA*, 34:1, 70-80; Woo, C.K., I. Horowitz, B. Horii and R. Karimov (2004) "The Efficient Frontier for Spot and Forward Purchases: An Application to Electricity," *Journal of the Operational Research Society*, 55, 1130-1136; Woo, C.K., R. Karimov and I. Horowitz (2004) "Managing Electricity Procurement Cost and Risk by a Local Distribution Company," *Energy Policy*, 32:5, 635-645.

⁵ Montana Public Service Commission (2004) "PSC COMPLETES REVIEW OF NORTHWESTERN ENERGY'S PLAN FOR PROCUREMENT OF ELECTRICITY DEFAULT SUPPLY RESOURCES," http://www.psc.state.mt.us/news/pr/20040813_PSC_Completes_Review_of_NorthWestern_Energy_Plan_For_Procurement_of_Electricity_Default_Supply_Resources.pdf; Public Service of Commission of Maryland (2008), Order 82015, Case No.9117: IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF INVESTOR-OWNED ELECTRIC COMPANIES' STANDARD OFFER SERVICE FOR RESIDENTIAL AND

1.4 Electricity Markets in California

California was one of the first states to deregulate its retail market in 1998, and the procurement plans of California's investor-owned utilities ("IOUs") continue to resemble those of utilities in deregulated jurisdictions in many respects. California suspended retail access for new customers in the aftermath of the 2000-2001 energy crisis in order to ensure that all electric ratepayers would contribute to recovering the cost of long-term power purchase agreements signed by the California Department of Water Resources ("DWR"). Customers who had direct access contracts in effect as of the date of suspension, September 21, 2001, have retained the right to remain on direct access.

Under current statute, retail access is to remain suspended until DWR no longer supplies power; the last DWR contract expires in 2015. However, the CPUC is currently considering options for lifting the suspension of direct access on an expedited basis. This introduces the possibility of the return of retail access relatively early in the economic lifetime of new generating assets procured as a result of the 2010 LTPPs. Moreover, cities and counties may elect to provide generation service to ratepayers within their local jurisdictions through Community Choice Aggregation ("CCA"). Thus, California's IOUs must continue to account for the possibility of departing load in their 2010 LTPPs.

Currently, California does not procure capacity through competitive markets, although this option remains under consideration at the CAISO and the CPUC. The Commission recognizes that while the Resource Adequacy proceeding (R.05-12-013) could lead to the creation of capacity markets and/or other arrangements in the future, in the interim, planning is still necessary to ensure adequate capacity. The CPUC addressed the

SMALL COMMERCIAL CUSTOMERS IN MARYLAND; American Public Power Association (2008) "Retail Choice States Continue to Debate Power Supply Issues," <http://www.appanet.org/files/PDFs/Powersupplyprocurement.pdf>.

challenges of maintaining adequate capacity and reserves in California, without compromising the longer-term goals of competition and customer choice, in D.06-07-029. The Commission directed IOUs to procure capacity to meet system-wide needs, allocating these costs among all benefiting customers, including those of other LSEs. This decision recognized the role of the IOUs in providing “backstop” capacity for all energy consumers within their physical service territories.

The years since the energy crisis have seen an intensification of California’s commitment to renewable resources and greenhouse gas reductions. SB 107, passed in 2002, established a 20 percent RPS that the IOUs are to meet by 2010. Subsequent statements from the Governor, the California Energy Commission (“CEC”), the CPUC and Integrated Energy Policy Reports have called for that standard to be increased to 33 percent by 2020. Most importantly, California’s Global Warming Solutions Act calls for California to reduce its greenhouse gas emissions to 1990 levels by 2020. Renewables and other low-carbon resources, and the transmission infrastructure required to integrate them reliably into the high-voltage grid, are large capital-intensive investments with long operating lifetimes. Modeling conducted for the CPUC indicates that meeting a 33 percent RPS could require some \$60 billion in generation and transmission investment by 2020 and seven new transmission lines.⁶ Most of this investment will likely be financed via long-term contracts secured by utility rate revenues.

1.5 Conclusion

The CPUC’s 2008 LTPP process is currently considering the type of long-term planning appropriate for California IOUs in light of these new realities. This survey aims to inform those efforts by providing information about planning and procurement

⁶ California Public Utilities Commission (2008). “Renewables Portfolio Standard Quarterly Report,” pg. 9, available at: http://docs.cpuc.ca.gov/word_pdf/REPORT/85936.pdf

processes in other jurisdictions. The survey covers both regulated and deregulated jurisdictions, and provides information about a wide range of practices. As such, the report does not recommend specific changes to California's future LTPPs. Instead, the report aims to seed the discussions that are already underway in that proceeding and inform the participation of stakeholders as they seek to find a reasonable balance for California.

2 California policy and regulatory context

2.1 Introduction

California's electricity market currently has elements of both the regulated and deregulated market structures seen elsewhere. While retail access is currently suspended to new customers in California, its possible return, along with the potential for CCA, means that California IOUs' procurement plans, like those of utilities in deregulated jurisdictions, must consider the possibility of departing load. While IOUs in California procure from a deregulated generation market to meet their electrical needs, the IOUs are also subject to extensive legislative and regulatory mandates that place severe constraints on resource options and require long-term investments secured by rate revenue, a situation that has more in common with regulated jurisdictions. California IOUs also must backstop the competitive market and procure new generation in their service areas to ensure there is sufficient supply to meet the total load. In this chapter, we summarize the regulatory and policy history in California since the State first moved toward deregulation in the late 1990s. This background provides a useful context for the consideration of resource planning challenges in California.

2.2 The 2000-2001 Energy Crisis and California's Policy Response

The deregulated California electricity market operated uneventfully during its initial period of April 1998 - May 2000. Wholesale spot market prices were relatively low and reliability was comparable to historic levels.⁷ However, the June 2000 - March 2001 crisis resulted in unprecedented price spikes, rolling blackouts, and financial insolvency for

⁷ Woo, C.K., D. Lloyd and A. Tishler (2003) "Electricity Market Reform Failures: UK, Norway, Alberta and California," *Energy Policy*, 31:11, 1103-1115; Woo, C.K. (2001) "What Went Wrong in California's Electricity Market?" *Energy*, 26:8, 747-758.

Pacific Gas & Electric ("PG&E") and Southern California Edison ("SCE"). While a detailed discussion of the energy crisis is beyond the scope of this report, it is clear that the financial effect of the crisis was amplified by California's policy of requiring utilities to procure their entire open position through the California Power Exchange's daily and hourly spot markets. FERC eliminated this requirement in December 2000, and the Power Exchange closed in February 2001.

California's subsequent policy responses have emphasized the role of long-term contracting as a means of providing rate stability. Forward contracts and tolling agreements replaced spot purchases when the DWR entered into a number of long term contracts to obtain dependable supply at stable prices. The DWR still maintains approximately 43,000 GWh, or about 15 percent of state retail sales, in long-term power contracts, though the last of these contracts will expire in 2015.⁸

In 2002, California passed Assembly Bill 57 (AB 57), requiring the CPUC to adopt policies and cost recovery mechanisms for long-term procurement by investor-owned utilities.⁹ AB 57 empowers the CPUC to

- (a) Ensure that the electric corporations create "a diversified procurement portfolio;"¹⁰
- (b) Assure "just and reasonable electricity rates;"¹¹

⁸ California Department of Water Resources "Determination of Revenue Requirements for the Period January 1, 2009 Through December 31, 2009", August 2008, available at http://www.cwrs.water.ca.gov/pdf_files/080608_2009_revreq.pdf

⁹ AB 57 (Stats.2002, Ch.850, Sec 3, Effective September 24, 2004), added Public Utilities Code § 454.5

¹⁰ AB 57 (Stats. 2002, Ch. 850, Sec. 3, effective September 24, 2002), added Pub. Util. Code § 454.5.

¹¹ Pub. Util. Code § 454.5(b)(9)(B)

- (c) Provide certainty to the electrical corporations in order to enhance their financial stability and creditworthiness;¹²
- (d) “Eliminate the need, with certain exceptions, for after-the-fact reasonableness reviews of an IOU’s prospective electricity procurement performed consistent with an approved procurement plan;”¹³ and
- (e) Assure that each electrical corporation “optimizes the value of its overall supply portfolio for the benefit of its bundled service customers.”¹⁴

As a result of AB 57, the CPUC established the LTPP proceeding. In 2001, the CPUC, through its Order Institution Rulemaking (“OIR”) R.01-10-024, began the process of re-establishing long-term planning in California. This first procurement proceeding was followed by R.04-04-003, R.06-02-13, and finally the current LTPP (or procurement) docket, R.08-02-007. The results of the last LTPP, as well as the direction for the current LTPP proceeding, are discussed later in this section.

2.3 California Policy Directed Towards Resource Procurement

California IOUs’ LTPPs must comply with a number of procurement targets mandated by legislative and regulatory actions. The major policies in this area are summarized below:¹⁵

¹² Pub. Util. Code § 454.5(c)

¹³ Pub. Util. Code § 454.5(d)(2)

¹⁴ CPUC Decision 03-12-062.

¹⁵ For a more complete discussion of California legislation, policies, initiatives and CPUC proceedings impacting the LTPP see Appendix A.

- *Loading Order:* The California Energy Action Plan¹⁶ establishes the preferred order in which California utilities are to meet their load in the long-term interest of consumers and taxpayers. The loading order states that, first, utilities are to reduce electricity demand through energy efficiency and demand response. Second, after all cost-effective demand-side measures are undertaken, utilities are to meet new generation needs with renewable and distributed generation resources. Third, remaining generation needs are to be met with clean fossil-fueled generation.
- *Renewables Portfolio Standard:* Senate Bill 1078 established the State's RPS program, requiring retail providers, excluding local publicly-owned utilities, to meet 20 percent of their retail sales from qualifying renewable energy sources by 2017. This RPS target was accelerated to 20 percent by 2010 in the 2003 Energy Action Plan, and codified into law under Senate Bill 107. The law does not mandate the publicly-owned utilities (POUs) to meet the 20 percent RPS by 2010, but does require the POUs to set their own RPS targets in keeping with the intent of the legislatures in SB 107. The legislation notes that electrical corporations must increase their procurement of renewable energy by at least 1 percent of their retail sales per year, until the 20 percent by 2010 target is met, or will face non-compliance penalty costs. Flexible compliance rules apply to these annual procurement targets, as described in D.08-02-008. While AB 107 places mandatory RPS requirements only on electrical corporations, the California Air Resources Board, the California Public Utilities Commission and the California Energy Commission have all recommended increasing the RPS target to a statewide target of 33 percent by 2020.

¹⁶ State of California, Energy Action Plan. Adopted by the CEC, CPUC, and Consumer Power and Conservation Financing Authority ("CPA") in May, 2003. P.4.

- *Greenhouse Gas Legislation:* Assembly Bill 32 requires the state to reduce greenhouse gas emissions back to 1990 levels by 2020. The details of implementing AB 32 are still under consideration, but the current California Air Resources Board ("CARB") proposal for AB 32 compliance includes increasing the state's RPS from 20 percent by 2010 to 33 percent by 2020. Other proposed AB32 implementation measures include increasing penetration of energy efficiency and combined heat and power, as well as putting a price on greenhouse gas emissions through a cap and trade mechanism.
- *Environmental Controls on Once-Through Cooling:* The California Water Resources Control Board is currently developing proposed regulations to reduce or eliminate the reliance of some of the state's generators on the environmentally harmful practice of once-through cooling ("OTC"). The proposed regulation could impact up to 20 percent of the state's energy generation and 21 thermal generating units, many of which are located in areas crucial for maintaining local resource adequacy and grid reliability.¹⁷
- *Resource Adequacy and Potential for Forward Capacity Markets:* Currently, the CPUC ensures that LSEs procure sufficient capacity to maintain service reliability through a resource adequacy requirement equal to 15 – 17 percent of peak load. The CPUC also requires that LSEs maintain forward contracting of 90 percent of retail sales. The CPUC is currently considering whether capacity requirements could be better met through a forward capacity market, rather than relying on utility RFOs. A decision to develop forward capacity markets could eliminate

¹⁷ Jones & Stokes. 2008. Electric Grid Reliability Impacts from Once-Through Cooling in California. April. (J&S 041808) Sacramento, CA. Available at: http://www.waterboards.ca.gov/water_issues/programs/tmdl/docs/power_plant_cooling/reliability_study.pdf

the need for a system-wide net-short position determination in the LTPP
(See Section 2.4 for a discussion of needs determination in the 2006 LTPP).

Achieving the state's procurement targets may imply that utilities should take a more active role in planning and procurement because of the need for long-term security for financing capital-intensive renewable and low-carbon energy investments, and financing increasingly expensive capacity resources for operational reliability. The current practice in California does not fully address the question of which resource investments are likely to result in the best means of meeting procurement targets. This is notwithstanding that somewhere in the range of \$60 billion in investments could be required to meet a 33% RPS by 2020.¹⁸

2.4 LTPP Process in California

The 2006 Long-Term Procurement Planning proceeding (R.06-02-013) sought to integrate the State's environmental and policy objectives as well as the State's market-based procurement objectives under a resource planning framework. The proceeding also combined the IOUs short-term procurement plan authority with the long-term procurement plans to create one combined procurement plan. This allowed the LTPP proceeding to make a need determination based on system need and bundled customer need, establish the resource specifics of those need determinations. The 2006 LTPP also sought "to integrate all procurement policies and related programs and serve as a check in point on the [Energy Action Plan] EAP loading order," and to demonstrate compliance with the state's greenhouse gas policies.¹⁹

¹⁸ CPUC, "Renewables Portfolio Standard Quarterly Report," July 2008, pg. 9, available at: http://docs.cpuc.ca.gov/word_pdf/REPORT/85936.pdf

¹⁹ Rulemaking 06-02-013, Order Instituting Rulemaking pgs. 15-25.

While some stakeholders expressed frustration with aspects of the 2006 LTPPs, including that they did not indicate how the IOUs would meet the state's goal of achieving 33 percent of retail sales from renewable energy, the IOUs contended that they had complied with the CPUC's directives in the LTPP process. While approving the 2006 LTPP plans, the CPUC's decision found that the IOUs' LTPPs were "deficient and spotty" in regards to applying the State's preferred loading order and in accounting for potential greenhouse gas emissions regulation and required the IOUs to "provide absolute GHG emissions, with cost implications, under various scenarios in their future LTPP filings."²⁰ The CPUC also noted in R.08-02-007 that a "primary objective of this effort will be to provide greater transparency with regard to how resource planning decisions are made."²¹

After the completion of the 2006 LTPPs, the Commission sought to lay the groundwork for an improved process in the 2008 LTPPs: "The methodology established in the Scoping Memo for long-term renewable resource planning was not as robust as we believe is necessary for effective resource planning decisions...We anticipate methodology that employs an integrated portfolio approach."²²

The CPUC has taken a number of steps to implement the integrated portfolio approach. Besides allowing more time for developing the 2010 LTPPs (by waiving the 2008 LTPP filings in favor of a proceeding to consider improvements to the 2010 LTPP filings) and welcoming substantive input from stakeholders, the CPUC has explicitly singled out issues to be addressed in the current (2008) LTPP docket. These issues include (a) standardization of input assumptions to the LTPPs; (b) better quantification of

²⁰ CPUC Decision 07-12-152 in Rulemaking 06-02-013, pp. 3, 299.

²¹ R.08-02-007, Appendix A, Preliminary Scoping Memo, p.A-5.

²² CPUC Decision 07-12-152 in Rulemaking 06-02-013, pg. 76.

energy efficiency's effect on the load forecast produced by the CEC; (c) treatment of uncertain future GHG regulation costs; (d) development of IOU GHG program inventory reports; (e) improved treatment of firm capacity from demand-side resources; (f) consideration of customer risk preference; and (g) consideration of procurement under the CAISO's Market Redesign and Technology Upgrade ("MRTU").²³ Hence, the outcome of the 2008 LTPP docket will aid the development of the 2010 LTPPs.

One may contend that the need for a 2010 LTPP process may be diminished by new market developments, including the MRTU, the potential implementation of forward capacity markets, greenhouse gas cap and trade markets, and tradable Renewable Energy Credit ("REC") markets. This conclusion is premature for two reasons. First, these markets are not yet in place and how they may function is not known at this point. Second, even if these markets become operational and function as designed, the development of complying portfolios (i.e., those that satisfy the procurement targets) with differing risk-cost and environmental tradeoffs requires an integrated portfolio approach, implemented via long-term resource planning and procurement. Hence, the 2008 LTPP Assigned Commissioner concludes "[i]t would be imprudent to assume at this time that other market structures will obviate the need for LTPP-authorized procurement and delay the timely development 2010 LTPP policy guidance... [R]egardless of what the Commission decides on market mechanisms in other proceedings, the IOUs will still need a robust planning process to effectively implement various policy mandates for their bundled customers."²⁴

²³ Assigned Commissioner's Ruling and Scoping Memo on the 2008 Long-Term Procurement Proceeding, Phase 1, R.08-02-007.

²⁴ Assigned Commissioner's Ruling and Scoping Memo on the 2008 Long-Term Procurement Proceeding, Phase 1, R.08-02-007, pg. 6.

3 Energy Procurement in Deregulated Jurisdictions

3.1 Introduction

This chapter examines how other deregulated jurisdictions address policy issues of interest to California. While direct access is currently suspended to new customers in California, the state's energy planning and procurement processes still resemble processes in other deregulated jurisdictions in many respects. Thus, it is instructive to consider planning and procurement processes in deregulated jurisdictions.

Many factors contributed toward the push toward deregulation; a unifying theme was the belief that increased competition would result in cost savings and more economically efficient development of electrical resources. According to this perspective, under deregulation, resource developers and investors will respond to market signals by allocating scarce capital and resources to projects with the highest potential value. The resulting resource mix will be optimal because efficient markets ensure that investments generate the highest economic value. At the same time, market forces will also allocate valuable electricity output to users with the highest willingness to pay.

Because of the reliance on market-based resource allocation, the energy planning and procurement processes in deregulated jurisdictions are substantially different from those in jurisdictions in which vertically-integrated utilities dominate. In deregulated markets, the focus of procurement regulation tends to be on the question of *how* to buy, which is driven by the goal of market competition made possible by rules on efficiency, transparency, and fairness. Unlike in regulated markets, the question of *what* to buy is not a focus, as market forces are expected to match customer preferences and supplier outputs and to guide investments with the best returns.

While deregulated market structures are typically aimed at facilitating retail access, utilities must nevertheless ensure continued, reliable service to customers that do not select competitive providers. This service, termed “provider-of-last-resort” (“POLR”) or “standard offer service” (“SOS”), is meant to be a transitional or last-resort service provided only until all customers are served by competitive suppliers.

Because of the nature of POLR service, utilities generally avoid long-term commitments to generating resources, and instead purchase short-term instruments (1-3 years) at market prices. This system ensures that (a) the utility does not incur any new “stranded” costs if market prices drop below the contracted cost of power and POLR customers depart for competitive service, and (b) the POLR service does not short-circuit the competitive market by offering prices that are more attractive than competitive suppliers can offer, i.e., that are below the prevailing market prices.

As discussed in the previous section, several components of California's restructuring were suspended by the legislature in the aftermath of the energy crisis, including new Direct Access. However, like utilities in other deregulated jurisdictions, the California IOUs generally do not meet growing bundled customer needs through the ownership of new generation or the signing of long-term contracts.²⁵ Rather, bundled customer needs are met through a combination of short-term market purchases and awards to third parties through a competitive, all-source RFO process. And like the utilities in other deregulated jurisdictions, California IOUs do not control the planning and operations of transmission infrastructure.

²⁵ California IOUs have been allowed to enter into long-term contracts for the purpose of maintaining system resource adequacy and to comply with renewable energy procurement requirements.

3.2 State of Retail Access

Table 1 below summarizes the proportion of residential and non-residential customers selecting competitive retail service providers in some of the North American deregulated jurisdictions. While deregulation efforts have been ongoing for many years, only Massachusetts, New York, and Texas show more than 10 percent of residential customer accounts served by competitive ESPs. The vast majority of the residential load in the deregulated jurisdictions is still served through procurement by a regulated utility.

Table 1: Customers & load served by direct access retail suppliers in deregulated jurisdictions

State (ISO)	Residential		Small Non-residential/ Commercial		Large Non-Residential/ Industrial		Total	
	% of Accounts	% of Load	% of Accounts	% of Load	% of Accounts	% of Load	% of Accounts	% of Load
Connecticut (ISO-NE) ²⁶	*	5.8%	*	64.7 %	*	64.7 %	*	37.5 %
Illinois ²⁷ (PJM/MISO)	0.0%	0.0%	11.9%	50.3 %	88.6%	92.6 %	1.0%	44.5 %
Maryland ²⁸ (PJM)	3.0%	3.5%	16.4%	20.5 %	24.8%	70.1 %	5.3%	37.7 %
Massachusetts ²⁹ (ISO-NE)	10.7%	11.5 %	22.7%	43.1 %	70.9%	85.1 %	12.5%	47.8 %
New York ³⁰ (NYISO)	14.3%	15.3 %	24.1%	50.6 %	50.3%	76.2 %	15.7%	44.0 %
Texas ³¹ (ERCOT)	33.9%	*	39.4%	*	61.0%	*	*	*
California ³²	0.6%	0.5%	1.5%	5.9%	10.3%	20.2 %	0.8%	8.0%

²⁶ Massachusetts Department of Energy Regulation, *Summary of Competitive Market 2007*.
http://www.mass.gov/doer/pub_info/summary_competitive_market_2007.htm

²⁷ Illinois Commerce Commission, *Electric Switching Statistics*,
<http://www.icc.illinois.gov/industry/publicutility/energy/switchingstatistics.aspx>

²⁸ Maryland Public Service Commission, "Electric Choice Enrollment Monthly Report All Investors Owned Utilities in Maryland Month Ending June 2008",
<http://webapp.psc.state.md.us/Intranet/samplecode/enrollmentrpt.cfm>

²⁹ Massachusetts Department of Energy Regulation, *Electric Customer Migration Data*,
http://www.mass.gov/Eoca/docs/doer/pub_info/0807.xls

³⁰ New York State Public Service Commission, "New York Electric Retail Access Migration Data for February 2008." <http://www.dps.state.ny.us/ElectricMigrationWebReportMar08.pdf>

³¹ Public Utility Commission of Texas, *Report to the 80th Legislature, Scope of Competition in Electric Markets in Texas*. http://www.puc.state.tx.us/electric/reports/scope/2007/2007scope_elec.pdf

³² Assigned Commissioner's Ruling Regarding Comments on Certain Direct Access Issues, Appendix A, Oct. 23, 2001. Data is as of Sept. 30, 2001, just after the suspension of Direct Access in California.
<http://docs.cpuc.ca.gov/Published/Rulings/10604.htm>

* - data not available

The picture is very different for non-residential customers. Table 1 indicates that a high percentage of large non-residential load is served by competitive ESPs in each of the five non-California jurisdictions surveyed. California, where Direct Access was suspended in 2001, is an exception. The percentage of large non-residential *accounts* served by competitive ESPs is uniformly smaller, sometimes significantly so, reflecting the fact that it is often the very largest non-residential customers that choose retail access, while many of the small non-residential customers continue to be served by their POLR, despite efforts to promote competitive options.

All of the deregulated jurisdictions continue to have POLR service. In some states, POLR service is provided by the regulated utilities (referred to as “local distribution companies” (“LDCs”). Though different jurisdictions have different guidelines governing how a LDC procures its electricity needs, they are all consistent in allowing the LDC to pass reasonably-incurred procurement costs through to rates.

None of the jurisdictions surveyed allow either retail or default service providers to collect a switching fee for consumers electing to subscribe to their service. However, all of the deregulated jurisdictions allow providers to establish contracts with penalties for early cancellation, much like those used by cell phone providers. Pennsylvania and Illinois require customers that choose standard offer or default service to continue taking that service for 12 months, though customers who are placed on SOS due to the failure of their retail provider are not subject to this requirement.

The standard offer service provided by the LDCs is highly variable depending on customer type and preferences. All LDCs have a basic service targeted at residential customers which does not have a time-of-use aspect, as well as a more differentiated time-of-use schedule for larger customers. Beyond this, however, SOS can be as varied as schedules under the regulated service of vertically-integrated utilities, with differentiation based on demand size, time-of-use, seasonal options, and more.

3.3 Procurement Processes for Default Service

Because utilities are regulated at the state level, the procurement of generation resources by a regulated LDC is governed by the regulatory commission in the state in which the LDC operates. The following sections discuss how LDCs in various deregulated markets address such questions as what to buy, when to buy and how to buy.

3.3.1 NEED DETERMINATION

With the exception of Pennsylvania, all of the deregulated jurisdictions surveyed had minimum time frames over which they were required to project load for procurement purposes. These time frames range from the very near term (between 6-12 months into the future) to the medium term (10 years). Table 2 below shows the minimum forecasting requirements by jurisdiction where specified.

Table 2: Time frame requirements for POLRs in deregulated jurisdictions

State	Minimum time frame for projecting load
Connecticut	Energy demand and capacity needs must be projected for three, five, and ten years
Illinois	Supply and demand balance must be projected for five years
Maryland	Six months for residential and small non-residential, three months for large residential
Massachusetts	One year for residential and small non-residential, three months for medium and large non-residential
New Jersey	One year for large non-residential, three years for residential and small non-residential
Pennsylvania	Not specified, suggested contracts of up to three years for residential and one year for small non-residential. Hourly- or monthly- priced service should be available for large non-residential customers.
Texas	Every two years, the Public Utility Commission of Texas selects POLRs, both volunteer and non-volunteer. Volunteer POLRs can specify the number of customers whose retail providers default on their service that they want to serve, while non-volunteer POLRs serve any customers beyond those amounts.
California	Month-ahead and year-ahead forecasts are required for all LSEs under CPUC jurisdiction under the Resource Adequacy program. The current LTPP process requires 10-year forecasting of load every 2 years, by IOUs only.

As a POLR, the regulated LDC is responsible for providing electricity to all customers not served by a competitive retail supplier. This can make the LDC's need

determination difficult, as customers can depart from or enter into the LDC's load obligations, depending on market conditions.

Without explicitly discussing load forecasting in the state's procurement process, Massachusetts requires a regulated LDC to acquire the necessary resources to serve all default service loads. This requirement places the forecast burden on the LDC.

New Jersey and Maryland have established procurement processes in which potential suppliers bid to serve a percentage of system load. While the utilities prepare load forecasts for use by supply bidders, these forecasts are used only to indicate the approximate load that a winning bidder will have to serve. Thus, the winning bidder is responsible for the detailed forecasting of the size and shape of the system load percentage won.

Other jurisdictions take a longer-term view for procurement purposes. In Illinois and Connecticut, utilities are required to submit a procurement plan that looks at the balance of loads and resources in the coming years. These forecasts must account for the effects of customer switching to a competitive retail provider, demand-side load reductions, and statewide renewable or emissions standards.

Pennsylvania does not explicitly require a regulated LDC to forecast load into the far future, due to the relatively short-term focus of their procurement process.

In contrast, Texas does not *a priori* specify who would be the POLR or how a POLR must procure energy. Rather, companies that can prove their ability to offer default service can volunteer to be a POLR.

In California, LSEs under CPUC jurisdiction must assess need in accordance with the Resource Adequacy program as defined in R.05-12-013 and R.08-01-025. LSEs must calculate resource adequacy on a month-ahead and year-ahead basis. Resource adequacy is equal to an LSE's forecast peak load for the month plus a 15 percent

planning reserve margin.³³ In 2007, the program was expanded to consider local area needs in addition to system-wide needs.

3.3.2 'PROVIDER OF LAST RESORT' PROCUREMENT PROCESS

All of the deregulated jurisdictions in Table 3 indicate that the goal of the POLRs in their area should be to accurately convey market signals to POLR customers to promote the competitiveness of alternative service providers, while protecting default service customers from large bill impacts due to variations in short-term energy prices.

However, Table 3 shows that the methods that the various jurisdictions employ to promote this goal vary widely. Connecticut expresses preference for the use of demand-side resources and renewable energy. Illinois requires submission of procurement plans to be filled by competitive bidding, without explicit preferences for demand-side resources. Maryland, Massachusetts and New Jersey auction default service loads so that the winning bidders have the burden of procurement for meeting their load obligations. While advocating competitive procurement, Pennsylvania does not have explicit procurement requirements. Texas emphasizes the ability of a voluntary POLR's ability to serve load, and allows the POLR to charge above-market rates. California favors all-source RFOs with 1-3 year contract periods, but IOUs have been allowed to enter into long-term contracts for the purposes of meeting resource adequacy and RPS goals.

³³ CPUC, 2006 Resource Adequacy Report, March 16, 2007, pp.5, 13.

Table 3: Procurement process in deregulated jurisdictions

State	Procurement Design
Connecticut ³⁴	Resource needs are met first by energy efficiency and demand reductions. Procurement plans must consider the extent to which renewable and combined heat and power facilities can meet demand, as well as how the overall portfolio mix will meet environmental goals and impact costs to consumers.
Illinois ³⁵	Large utilities (greater than 100,000 customers) submit a proposed procurement plan to the Illinois Power Authority, which consolidates these plans into a statewide procurement plan. Resources are acquired through a competitive bidding process, which allows for self-build bids from the utilities.
Maryland ³⁶	Competitive bidding process for full requirements service as a percentage of total load. Resources are procured with two-year rolling contracts, two procurements per year for residential and small non-residential. Supply for large non-residential customers is done with three month contracts. The Public Service Commission recently initiated a new proceeding examining whether they should move to a 10 to 15 year planning horizon.
Massachusetts ³⁷	Standard Offer Service is procured through rotating auctions. Residential load is served by overlapping competitive solicitations every six months in which 50% of load is contracted for a period of one year, while medium and large commercial customers are served by quarterly solicitations for 100% of their load.
New Jersey ³⁸	Full Requirements Service for a percentage of New Jersey load is procured in annual descending clock auctions. ³⁹ Each year, resources required to serve 33% of residential load are procured for a duration of three years, while resources required to serve 100% of large commercial and industrial load are procured for a duration of one year.

³⁴ Public Act No. 07-242, Sec. 51.

³⁵ Public Utilities Act, 220 ILCS 5/16-111.5.

³⁶ Maryland PSC Case No. 8908, Phases I and II Settlements.

³⁷ Massachusetts Department of Public Utilities, <http://www.mass.gov>.

³⁸ New Jersey Statewide Basic Generation Service Electricity Supply Auction Overview, <http://www.bgs-auction.com/bgs.auction.overview.asp>

³⁹ A descending clock auction proceeds in rounds, with each round consisting of a price at which potential suppliers bid the percentage of load they are willing to supply at that price. As the rounds proceed, the offered price gets progressively lower, until the supply bid in at a given price is just sufficient to meet the need.

State	Procurement Design
Pennsylvania ⁴⁰	Pennsylvania allows POLRs the most latitude in their procurement of resources. The Pennsylvania Public Utilities Commission does not dictate any specific procurement methods, but rather has provided a series of suggestions as to what they expect from POLRs, with the goal of achieving standard offer service that accurately reflects prevailing market conditions. The implementation of these suggestions is left up to the utilities themselves.
Texas ⁴¹	Volunteer POLRs must demonstrate their ability over the following two years to quickly serve customers whose retail electric providers default. They can do this from their existing portfolio or through market purchases. POLR rates allow for the pass-through of costs, and include an energy aspect that is capped at 130% of the hourly market clearing price of energy.
California	Loading order specifies procurement order for IOU POLRs; demand-side management first, followed by renewables, with clean fossil fuel making up the balance. Procurement is through all-source RFOs, with 1-3 year time horizon. IOUs are allowed to enter into long-term contracts to meet reliability and RPS goals.

3.4 Procurement to Meet Renewables Portfolio Standards

Like California, many of the deregulated jurisdictions also promote the development of renewable energy resources through state RPS statutes. These statutes require LSEs, including both regulated LDCs and competitive retail providers, to serve a certain percentage of retail sales with renewable resources. Table 4 below shows the RPS targets for each state, including both regulated and deregulated states.

RPS compliance can be difficult in a deregulated market where energy is procured in relatively short (1-3 years) time periods, because many renewable projects have difficulty obtaining financing and control of their sites without a longer purchasing commitment for their power. As shown in Table 5, some jurisdictions have recently begun allowing LDCs to sign longer-term contracts with renewable energy suppliers to ensure that there is sufficient financial incentive to invest in new renewable resources.

⁴⁰ Pennsylvania PUC, Final Rulemaking Order in Docket L-00040169.

⁴¹ PUC Texas, Electric Rule Chapter 25.43. <http://puc.state.tx.us/rules/subrules/electric/25.43/25.43.pdf>

Table 4: Renewable Portfolio Standards by State

State	Renewables Requirement
Arizona	15% by 2025
California	20% by 2010, goal of 33% by 2020.
Colorado	In 2007, the RPS changed to 20% by 2020. The previous requirement was 10% by 2015.
Connecticut	23% by 2020.
Delaware	20% by 2019.
District of Columbia	11% by 2022, Tier system. 1.5% from Tier 1 by 2007, increasing gradually to 11% by 2022. 2.5% from Tier 2 by 2007, decreasing gradually to 0% by 2020.
Hawaii	Gradually to 11% by 2022. 2.5% from Tier 2 by 2007, decreasing gradually to 0% by 2020.
Illinois	25% by 2025, starting at 2% in 2008; 75% from wind.
Iowa	Requires investor-owned utilities to contract a combined total of 105 megawatts (MW) of generation from renewable resources.
Maine	30% of retail sales in 2000 and thereafter as a condition of relicensing, plus an additional 10% by 2017.
Maryland	9.5% by 2022 under a tiered system.
Massachusetts	1% of sales in new renewables in 2003 or 1 year after any renewable is within 10% of average spot market price; increasing by 0.5% per year to 4% by 2009 and 1% per year thereafter.
Minnesota	25% by 2025. For Xcel Energy 30% by 2020. For other electricity providers: goal of 25% by 2025.
Missouri	11% by 2020.
Montana	15% by 2015.
Nevada	In 2007, the RPS changed to 20% by 2015 from the previous state requirement of 5% by 2003, rising by 2% every two years until reaching 15% by 2013.
New Jersey	The state requirement of 0.5% effective 2001, increasing to 1% by 2006, then increasing by 0.5% per year to 4% by 2012, was replaced with 22.5% by 2021 and thereafter.
New Hampshire	25% by 2025.
New Mexico	In 2007, the RPS changed to 5% by 2006, increasing to 10% by 2011, 15% by 2015 and 20% by 2020. Rural electric cooperatives: 5% by 2015, increasing to 10% by 2020.
New York	25% by 2013.
North Carolina	12.5% Renewables and Energy Efficiency by 2021, up to 40% of Standard met with efficiency.
Oregon	Large utilities: 25% by 2025, Small utilities: 10% by 2025, Smallest utilities: 5% by 2025.
Pennsylvania	18% by 2020 (8% from Tier 1, 10% from Tier 2). For Tier 1, 1.5% by 2007 increasing 0.5% per year.
Rhode Island	16% by end of 2019.
Texas	5,580 MW by 2015.
Vermont (goal)	10% by 2012 (not a requirement, but an established goal).

State	Renewables Requirement
Virginia (goal)	12% of base year (2007) sales by 2022, (not a requirement, but an established goal).
Washington	3% by 2012, 9% by 2016, and 15% by 2020.
Wisconsin	In 2006, state requirement of 2.2% by 2010 raised to 10% by 2015

Source: <http://www.awea.org/legislative/pdf/State%20RPS%20factsheet%20Nov%202007.pdf>

Table 5: LDC Procurement to meet renewable portfolio standards

State	Procurement Design
Massachusetts	Procurement rules amended to allow LDCs to use long-term contracts to comply with RPS.
Maryland	LDCs directed to conduct studies on contract lengths
New Jersey	Some utilities required to enter into long-term contracts for solar
Connecticut	Explicitly allow long-term contracts and LDCs must comply with RPS
Illinois	Explicitly allow long-term contracts and LDCs must comply with RPS
Pennsylvania	Explicitly allow long-term contracts and LDCs must comply with RPS
Texas	Explicitly allow long-term contracts and LDCs must comply with RPS
California	Explicitly allow long-term contracts and LDCs must comply with RPS

In Massachusetts, where POLR electricity is normally procured in 12-month blocks every six months, the governor signed Senate Bill 2768 into law on July 2, 2008. This bill requires the electric distribution companies to solicit proposals for and enter into long-term contracts (provided they are cost-effective) for up to three percent of their total energy load from renewable resources twice during the five years beginning July 1, 2009. This measure is intended to facilitate the financing of renewable energy projects in the state.⁴² In Maryland, the Public Service Commission issued an order on July 3, 2008, directing LDCs to conduct studies to examine possible procurement strategies under

⁴² Senate Bill 2768, <http://www.mass.gov/legis/bills/senate/185/st02pdf/st02768.pdf>

different contract lengths, with an eye to how they align with various state regulations, including the 20 percent RPS target by 2022.⁴³

The New Jersey Board of Public Utilities is following suit, announcing on July 30, 2008 that it would require some utilities to enter into long-term contracts for solar renewable energy credits, in order to spur further investment in solar generation to comply with the minimum solar requirement by 2021.

California IOUs must meet aggressive RPS standards. The Commission allows IOUs to enter into short-term contracts of less than 10 years, longer-term contracts of over 10 years subject to some requirements, and even to consider utility-owned renewable generation to help ensure that IOUs are able to meet their RPS requirements.⁴⁴

In Texas, LSEs are required to provide a number of Megawatts (“MWs”) of renewable energy, rather than a percentage of total load from renewable sources. The MW targets by LSE are determined by the RPS program administrator based on their proportion of the total load served in Texas.

The procurement guidelines in the remaining jurisdictions (Connecticut, Illinois, and Pennsylvania) explicitly allow long-term contracts for their POLRs, and place the burden of complying with any RPS on the LSE. All of the jurisdictions surveyed allowed the use of RECs to comply with standards. In California, the CPUC released a

⁴³ MD PSC Order 82105, http://webapp.psc.state.md.us/Intranet/CaseNum/NewIndex3_VOpenFile.cfm?ServerFilePath=C%3A%5CCasenum%5C9100%2D9199%5C9117%5C162%2Edoc

⁴⁴ Rulemaking 06-05-027, Decision 08-02-008, pgs. 8 and 32.

proposed decision in March 2009 authorizing the use of tradable RECs for compliance with the state's RPS.⁴⁵ The final decision was not available as of this report's release.

3.5 Planning Processes Sponsored by the ISOs/RTOs

All of the deregulated jurisdictions are members of RTOs, which coordinate the planning processes of different LDCs that may disperse over multiple jurisdictions to ensure the reliability of the increasingly large and interconnected systems. This is usually done through a combination of capacity markets and long-term transmission planning, though each RTO implements these tools in a different way. FERC Order 890 requires that transmission providers undertake a coordinated, open and transparent planning processes. In California, this role is played by the California Independent System Operator, which oversees long-term transmission planning for reliability, but does not currently oversee a capacity market. RTOs may sponsor planning initiatives on an *ad hoc* basis, as ISO New England did with its New England Electric Scenario Analysis study. No formal regional generation planning takes place in any of the jurisdictions.

3.5.1 PJM INTERCONNECTION

PJM Interconnection, LLC serves customers in New Jersey, Pennsylvania, Delaware, Maryland, Virginia, West Virginia, Kentucky, Tennessee, Ohio, Indiana, Michigan, and Illinois. PJM ensures that it will be able to meet its load-serving obligations through the recently-implemented Reliability Pricing Model ("RPM") and the Regional Transmission Expansion Planning Process ("RTEPP").

The RPM induces generation investments via market-based incentives. The RPM serves as PJM's capacity market, consisting of an annual auction to contract capacity for three

⁴⁵ Rulemaking 06-02-012, Proposed Decision mailed March 26, 2009.

years into the future. Capacity payments in the RPM are differentiated to encourage the efficient siting of generation resources, with higher payments to capacity in those areas that are constrained by a lack of available import capacity or internal generation resources. The capacity price in a zone is set at the market clearing level, at which the total amount that the winning bidders are willing to supply is equal to the total amount required in the zone.

The RTEPP is designed to ensure the reliability of the transmission system, and is conducted five years ahead of the planning year to ensure sufficient time to site and construct transmission lines approved through this process, and look out as far as 15 years – and even farther in some cases – to examine what resources will be necessary in the more distant future.

3.5.2 NEW ENGLAND INDEPENDENT SYSTEM OPERATOR (ISO-NE)

ISO-NE serves load in Vermont, New Hampshire, Maine, Massachusetts, Connecticut, and Rhode Island. It employs the Forward Capacity Market (“FCM”) to ensure reliable levels of capacity, and prepares annual Regional System Plans that examine the ability of the system to provide reliable service 10 years into the future. The FCM in ISO-NE is a descending clock auction, where the capacity price starts out high and is reduced until the market clears at the required amount of capacity. It also allows for regional differentiation by establishing capacity requirements for import- and export-constrained areas.

ISO-NE’s Regional System Plan provides a broad look at the system over the next 10 years. The plan assumes that all generators that cleared in the most recent Forward Capacity Auction will be available for the full ten years, and adds queued projects that ISO-NE expects to be completed in the near term but did not bid into the Forward Capacity Auction. ISO-NE proposes transmission solutions to the problems that are identified, and identifies those areas in which additional generation or demand-side

resources could have a significant impact on the need for new transmission. Solutions are evaluated in a stakeholder process.

3.5.3 NEW YORK INDEPENDENT SYSTEM OPERATOR (NYISO)

The NYISO is only responsible for New York State itself, unlike PJM or ISO-NE that serve multiple states. The NYISO capacity auction enables the LSEs in New York to procure the capacity necessary to meet their own capacity requirements. A capacity demand curve is established for relevant areas (capacity-constrained areas and the state as a whole) and the clearing price is set by the lowest price at which there is sufficient capacity to meet capacity requirements. The NYISO also performs an annual 10-year reliability assessment, assessing the amount of resources needed to maintain reliability, and supplementing this with regulated backstop solutions where appropriate.

3.5.4 ELECTRIC RELIABILITY COUNCIL OF TEXAS (ERCOT)

ERCOT's long-term planning process looks at general development scenarios to project the need for transmission in the future. The Public Utilities Commission of Texas specifies four wind development scenarios, each assuming a certain level of wind development in five Competitive Renewable Energy Zones (CREZs). ERCOT uses these scenarios to develop long-term transmission plans that will allow the wind developed in these CREZs to serve the load pockets elsewhere in the state.

In contrast to PJM, ISO-NE, and NYISO, ERCOT does not have a capacity market. Instead, it employs a series of mechanisms that are "intended to encourage market participants to build and maintain a mix of resources that sustain adequate supply of electric service in the ERCOT region."⁴⁶ These primarily consist of guidelines governing

⁴⁶ Public Utility Commission of Texas. §25.505(a).
<http://www.puc.state.tx.us/rules/subrules/electric/25.505/25.505.pdf>

the frequent provision of system adequacy reports and notifications of generator or load changes. ERCOT also maintains a reliability and operations subcommittee that performs planning assessments for them.

3.5.5 CALIFORNIA ISO (CAISO)

The CPUC and the CAISO are considering whether to develop a forward capacity market to supersede the state's current capacity procurement measures, in the hopes of providing a more efficient allocation of resources for capacity procurement through market price signals. In the interim, California applies a combination of short-term capacity procurement measures through the CAISO, and longer-term approaches towards capacity procurement through the CPUC. The cost-allocation mechanism adopted in D.06-07-029 enables IOUs to procure capacity for system resource needs with the costs being shared among all customers in the service territory.

The CAISO, following provisions in its Open Access Transmission Tariff (OATT), maintains an interconnection queue of proposed generation projects. Utilities may also propose transmission upgrades to maintain grid reliability, which are evaluated by the CAISO separately from projects in the interconnection queue. In addition, in compliance with FERC Order No. 890, the CAISO produces a long-term transmission plan for California in an effort to bring together industry information on projected load growth, proposed generation projects, re-powering and retiring, and planned transmission projects.⁴⁷ Thus, transmission planning in California requires coordination between utilities, independent energy producers, and the CAISO, as well as the CEC and CPUC which are responsible for permitting transmission projects. While many current initiatives seek to streamline the transmission planning process, coordination

⁴⁷ See for example, the 2008 CAISO Transmission Plan available at:
<http://www.caiso.com/1f52/1f52d6d93a3e0.pdf>

between utilities and the CAISO is likely to remain a necessary feature of transmission planning in California.

3.6 Limitations of Resource Planning in Deregulated Jurisdictions

Our survey of deregulated North American jurisdictions shows that, for the most part, these jurisdictions do not undertake long-term resource planning at the utility level. Rather, utility-level activity tends to be limited to short-term (1-3 years) or medium-term (5-10 years) procurement planning that focuses on *how* to buy and *how much* to buy, without addressing the question of *what* to buy over a long time horizon.

Long-term planning is occurring, to some extent, at the regional level through RTOs and ISOs. These planning efforts tend to focus on long-term transmission reliability and on the creation of market mechanisms, such as capacity markets or renewable energy credits, to facilitate the implementation of policy goals. These efforts are made more complicated in multi-state jurisdictions by the fact that no single entity is responsible for setting policy goals. In multi-state jurisdictions, such as PJM and ISO-NE, states have little control over these regional planning processes.

As the limitations of this structure with respect to realizing policy goals such as the fostering of renewable energy generation have become more apparent, some jurisdictions have begun creeping back toward long-term planning. For example, Massachusetts, Maryland, and New Jersey have taken steps to allow the use of long-term procurement contracts for renewables, as discussed above. In addition, the Maryland Public Service Commission has recently initiated a new proceeding examining whether the state should move to a 10 to 15 year planning horizon.

California differs from the other deregulated jurisdictions in several respects that suggest an expanded use of long-term utility planning. First, the state's legislature (e.g., AB 57⁴⁸) mandates, and CPUC decisions amplify,⁴⁹ that the CPUC must implement an integrated portfolio approach to develop resource and procurement plans that comply with legislated procurement targets (e.g., RPS and GHG emissions). Second, the California IOUs operate within a single regulatory jurisdiction, and the California ISO encompasses the same geography. Thus, state policy-makers may have the opportunity to wield greater influence here than in regions where RTOs span multiple states. Third, California IOUs currently rely on RFOs to obtain most of their energy and capacity needs. California has not decided whether to implement capacity markets to meet the Resource Adequacy requirements nor has it implemented auctions in which the IOUs would sell off their load obligations. Even if such markets existed, California's practice of signing long-term energy supply contracts might nevertheless warrant long-term planning to determine if the LSE portfolios had acceptable levels of costs and risks. Thus, an examination of regulated jurisdictions with traditional long-term integrated resource planning is also warranted, and is provided in the following chapter.

⁴⁸ AB 57 adds section 454.5 the Public Utility Code, requiring, in part, that utilities perform planning to specify the duration, timing, and quantities of electrical supply products to be acquired; assess associated price risk; and provide justification for the choices.

⁴⁹ The decisions in R.04-04-003, R.06-02-013, and R.08-02-007 suggest that the Commission increasingly requires the IOUs to undertake integrated resource planning in their LTPP filings.

4 Resource Planning in Regulated Jurisdictions

4.1 Introduction

This chapter presents a summary of results from our survey of utility resource planning practices in regulated jurisdictions. The sample, shown in Table 6 below, is made up mainly of utilities in the western U.S., where periodic resource planning filings by utilities are common, though we also include a Midwestern, a Southern, and a Canadian utility. Though not a utility, the Northwest Power and Conservation Council was chosen to round out the list as it exists specifically for the purpose of resource planning.

Table 6: Resource Planning Survey Sample

Utility / Planning Entity	Description	Approx. Peak Load
Northwest Power & Conservation Council	Regional planning council for the Federal Columbia River Power System with members appointed by the governors of Oregon, Washington, Idaho and Montana.	36,000 MW.
PacifiCorp	Investor-owned utility serving ~1.7 million customers in California, Oregon, Washington, Idaho, Wyoming, and Utah	10,000 MW
Idaho Power	Investor-owned utility serving ~1 million customers in southern Idaho and eastern Oregon.	2,500 MW
Puget Sound Energy	Investor-owned utility serving ~1 million customers in northwestern Washington.	5,000 MW
Public Service Colorado (Xcel Colorado)	Investor-owned utility (subsidiary of Xcel energy) serving parts of Colorado, New Mexico, and Texas.	7,000 MW
Avista Energy	Investor-owned utility serving approximately 350,000 customers in parts of Washington and Idaho.	1,700 MW
Arizona Public Service	Investor-owned utility serving parts of Arizona (the largest electric utility in Arizona)	8,000 MW
Nevada Power / Sierra Pacific Power	Investor-owned utility serving over 1 million customers in Nevada and northeastern California.	8,000 MW
Public Service Company of New Mexico	Investor-owned utility serving roughly 500,000 customers in New Mexico	1,900 MW

Utility / Planning Entity	Description	Approx. Peak Load
Georgia Power Company	Investor-owned utility (subsidiary of Southern Company) serving over 2 million customers in Georgia.	15,000 MW
Seattle City Light	Municipal utility serving over 300,000 customers in the Seattle, Washington area.	1,800 MW
Northern States Power (Xcel Minnesota)	Investor-owned utility (subsidiary of Xcel energy) serving parts of Michigan, Minnesota, North Dakota, South Dakota, and Wisconsin.	10,000 MW
British Columbia Hydro	Provincial Crown Corporation serving approximately 1.7 million customers in British Columbia.	10,000 MW

For comparison, we also summarize in this chapter the practices of the California IOUs. While California IOUs operate in a restructured market, including them in this chapter allows a side-by-side comparison with the regulated utilities performing traditional integrated resource planning.

We relied on the utilities' most recent resource planning filings and other publicly available documents to gather the information summarized herein. This chapter summarizes utility planning practices as described in those documents and, in that sense, is a snapshot in time of each utility's practices.

4.2 Range of approaches to resource planning

This chapter summarizes planning practices across a range of issues. At a high level, we found many similarities in utility planning practices and some areas of divergence. Table 7, below, provides an overview of selected practices across the utilities we surveyed.

Table 7: Summary of selected utility planning practices

	NWPCC	PacifiCorp	Idaho Power	PSE	PSCo	Avista Energy	APS	NPC / SPPC	PNM	Georgia Power	SCL	NSP	BC Hydro	PG&E	SCE	SDG&E
Needs Assessment What reliability constraint is used?	5% LOLP	12-15% PRM	95 th percentile peak demand	15% PRM	16% PRM	10% PRM + 90 MW	15% PRM	NPC 12% SPPC 15% PRM	12-20% PRM	13.5 – 15% PRM	95 th percentile peak demand	15% PRM	14% PRM	15-17% PRM	15% PRM	15-17% PRM
Planning Period How many years considered?	20	10	20	20	40	20	20	30	20	20	20	40	20	10	10	10
Action Plan Is there a shorter focus period, and if so, how many years?	5	N/A	N/A	N/A	8	10	7	1-3	5	N/A	N/A	15	N/A	N/A	N/A	N/A
Portfolios How many were considered?	1,400	17	12	24 +	Hundreds +	Hundreds +	5	NPC 10 SPPC 4	Hundreds +	unspecified	12	Thousands	17	3	2	1
Portfolio Method Optimization software used to create portfolio?	Yes	Yes	No	No	Yes	Yes	No	No	Yes	No	No	Yes	No	No	No	No
Cost Metric What was the primary cost metric used in portfolio analysis?	PVRR	PVRR	PVRR	PVRR	PVRR	PVRR	PVRR	PVRR	PVRR	PVRR	PVRR	PVRR	PV of incremental costs	PVRR	PVRR	PVRR
Risk Assessment How many scenarios / sensitivity cases were considered?	750	16	4	6	12	4	10	NPC 50 SPPC 12	~90	30+	6	12+	unspecified	4	2	3
Risk Assessment Other than scenarios / sensitivity cases, what other measures of risk were used?	TailVaR	TailVaR	N/A	TailVaR	N/A	Std Dev of costs	N/A	N/A	TeVaR	N/A	TeVaR	N/A	TailVaR	TeVaR	TeVaR	TeVaR

As shown in Table 7, one area of consistency in utility resource planning practice is the term of the study period; almost all utilities use a 20-year study period. Within this study period, however, some utilities chose to highlight a shorter procurement plan or action plan period (usually 5-10 years).

Two other areas where utilities were largely aligned in their approaches were reliability planning and cost metrics. For reliability planning, most utilities treated a planning reserve margin as a constraint to their portfolio development, and the level of reserve was usually set at around 15 percent. In evaluating the cost of their portfolios, most utilities relied primarily on the Present Value Revenue Requirement ("PVRR") or some equivalent calculation.⁵⁰

On the other hand, in the development of portfolios and assessment of portfolio risk, utilities exhibited a wider variety of approaches. The first point of variance is in the number of portfolios developed by each utility. Some utilities used optimization software to generate and evaluate hundreds, or even thousands, of portfolios. Other utilities created portfolios "by hand," which, for obvious reasons, results in evaluation of a much smaller number of portfolios. But even within this category there was substantial variation, with some utilities creating five or fewer portfolios while others created closer to 20 or more – a significant difference when portfolios are created manually.

A second point of variance has to do with the treatment of risk in the evaluation of portfolios. Some utilities relied exclusively on scenario and sensitivity analyses to evaluate risk, while others also included a stochastic measure of portfolio risk, such as

⁵⁰ Some utilities describe metrics that we take to be equivalent to PVRR, such as "Cumulative Present Worth of the Revenue Requirement" or "present value of portfolio costs." We have referred to all of these as PVRR in Table 7.

TailVaR or To-expiration-Value-at-Risk (“TeVaR”). The number of scenarios or sensitivity cases evaluated varied widely, ranging from as few as 3 or 4 to dozens or more.

Clearly there is an inherent tension between the desire to be as thorough as possible in the analysis, and the need to control the costs and resources used to complete it. Avista Energy notes that the four stochastic futures prepared for its analysis consumed 8,500 hours of central processing unit time and created a 450 gigabyte database.

On this issue and others in this report, we make no determination of the “right” level of detail, or the “best” available method. Rather, our intent with this survey is to illuminate the range of approaches and methodologies used in resource planning and inform discussion among parties going forward.

Each element is examined more closely below. Appendix B provides more detailed write-ups of each individual utility. A list of sources is provided in Appendix C.

4.3 Load Forecasting

Accurate load forecasts are essential for utility resource planning as these forecasts partially drive the amount of energy and capacity that the utility will need over the planning period.

4.3.1 NON-CALIFORNIA PRACTICE

A common method of load forecasting is econometric modeling, which seeks to predict future load by estimating the relationship between load and other variables. Not surprisingly, projections of population and economic growth are key determining factors (see Table 8 , below). Thus, a load forecast necessitates forecasts of these economic and demographic variables. Almost all utilities surveyed relied on external consultants for forecasts of economic and population growth. Public data sources, such as projections provided by the Energy Information Administration (“EIA”) were also referenced. Creation of a high, medium, and low load forecast was common.

Some utilities, like Seattle City Light, relied entirely on statistical “top down” modeling of time series data on sales and loads, while others, such as Avista Energy and Public Service Colorado, used a much more data- and time-intensive “bottom up” approach, considering such factors as appliance saturation and efficiency trends, and then estimating average future use by customer type before multiplying this usage assumption by the projection for customer class size (based on economic and population forecasts).

Beyond “top down” vs. “bottom up” modeling, utilities can be separated by the number of “sub-forecasts” that were aggregated to create the overall forecast. Separate examination of Residential, Commercial, and Industrial classes was standard, but some utilities took a more detailed cut. Seattle City Light, for example, separately estimated nine different customer sectors.

In addition, many utilities, such as Puget Sound Energy and Idaho Power, made adjustments for known or expected changes taking place at their larger customers. Others carefully modeled potential changes that could affect their largest industries – like BC Hydro, which considered not only pulp and paper demand, but also the possibility or level of beetle infestation when forecasting usage for its forestry customers.

Finally, utilities varied in the range of forecasts they created, and in their approach to determining this range. Some utilities assigned probabilities to their forecasts – usually this was expressed as the likelihood that observed load will be equal to or lower than the forecast. For example, Idaho Power created a 50th, 70th, and 90th percentile forecast, with the expectation that the 90th percentile forecast would be exceeded in only one of ten years. Northern States Power and BC Hydro both used Monte Carlo analysis to develop a 90 percent confidence range for low and high forecasts, within which actual load was expected to fall. One utility – Public Service of Colorado – explicitly took into account the possibility of global warming in creating a high forecast. As a general rule, utilities use their base forecast to set the planning reserve level.

4.3.2 2006 CALIFORNIA LTPP PRACTICE

In California, load forecasts are, in effect, provided to the utilities by the CEC. D.04-01-050 finds that “[t]he utilities should begin their analysis of their needs by relying on the information and analysis contained in the CEC’s Integrated Energy Policy Report and should incorporate that information to form a base case” (p.93). While the decision makes clear that the ultimate forecasting responsibility lies with the utilities, the burden is on the utilities to “explain the reasons for not adopting the IEPR case as its base case” should it choose to do so.⁵¹

The CEC forecast is based on a mix of “bottom-up” and “top-down” methodology. The bottom-up methodology, similar to that described earlier in this section, looks at energy end-uses and processes for the residential, commercial, and industrial sectors.

Agricultural and water pumping forecasts are based on top-down econometric modeling. The CEC forecast is further divided into several distinct climate zones, with economic and demographic projections, as well as weather variance, at the climate zone level.

In the 2006 LTPPs,⁵² each California IOU treated the CEC forecast somewhat differently, however. PG&E created three forecasts: a low forecast corresponding to the CEC low forecast; a base forecast corresponding to the CEC *high* forecast; and a high forecast which escalated the CEC high forecast by an additional 0.3 percent. SCE used the CEC forecast as one reference point, and developed its own forecast for comparison. SDG&E

⁵¹ D-07-12-052 affirms the Commission’s decision that the IOUs are to use the CEC’s forecast in their LTPPs and specifies further that “for purposes of granting procurement authority, need determination should be based on the CEC’s base forecast under baseline (1-in-2) temperature conditions pursuant to D.04-12-048” (pp. 28-29).

⁵² Descriptions of IOU planning practices in this chapter are based on the 2006 LTPPs, unless otherwise noted.

used the CEC forecast for the base case, but developed its own high and low forecasts covering a wider range of outcomes than the CEC high and low forecasts.

Table 8 summarizes the load forecasting methods used by each of the utilities we surveyed.

Table 8. Load Forecasting Methodologies

Utility/Regional Planning Authority	Load Forecasting Methodology
NWPPC	Update to detailed Demand Forecasting System (DFS), which produced detailed forecasts of end-use by sector. Updates based on population and employment. For Direct Services Industries (mainly aluminum smelters), a “simple” model based on electricity price forecasts.
PacifiCorp	Econometric modeling based on county and state level forecasts of employment and income provided by Global Insight and/or public agencies.
Idaho Power	Three forecasts produced: 50 th percentile (expected), 70 th percentile, and 90 th percentile. Largely based on an economic forecast provided by consultants. Separate forecasts for each major customer class, with individual forecasts for five special contract customers.
Puget Sound Energy	Econometric modeling with national macroeconomic inputs based on consultant forecasts, regional inputs based indirectly on data from the Northwest Power and Conservation Council, and local input based on PSE knowledge of planned expansions.
Public Service Colorado (Xcel Colorado)	High, base, and low forecasts, in accordance with Commission rules. Based on economic projections from consultants. High and Low forecasts bookmark a 90% confidence band. Residential and Commercial forecasts based on a Statistically-Adjusted-End-Use (SAE) approach. PSCo addresses the possibility of global warming in the High scenario.
Avista Energy	“Bottom up” approach, summing per-customer usage with number of customers across different rate classes. National and county-level employment and population forecasts are purchased from consultants. Sales forecasts are based on 30-year normal temperatures.
Arizona Public Service	Population-based forecast – little detail provided in planning document.

Utility/Regional Planning Authority	Load Forecasting Methodology
Nevada Power / Sierra Pacific Power	Population-based and derived based on data from the UNLV Center for Business and Economic Research; projections for hotel/motel room additions; econometric forecasts of energy need by customer class; and effects of state legislation, among other factors.
Public Service Company of New Mexico	Based on population projections and assumptions regarding usage per customer.
Georgia Power Company	A combination of end-use and econometric analyses. Considers economic growth, migration to state, appliance efficiencies, and fuel costs. Information sources include economic forecasting services and customer surveys.
Seattle City Light	Modeling based on correlation between load history and history of demographic and employment variables. Adjustments may be made based on knowledge of specific industrial customers' load-affecting plans.
Northern States Power (Xcel Minnesota)	For Residential, Commercial, and Industrial customer classes, econometric modeling with underlying variable forecasts (economic and population growth, etc) provided by consultants. For remaining classes, trend analysis is used. Peak planning is based on a 90% confidence interval that actual peak demand will be at or lower than the planning value.
British Columbia Hydro	Bottom-up methodology. Residential forecasts consider use reduction and housing starts. Commercial forecasts consider BC economy. Industrial forecasts consider global economic conditions and industry-specific developments. Information is provided by consultant AMEC. Monte Carlo simulation is used to determine confidence bands. Incremental load savings due to changes in rate structure are included in the modeling.
Pacific Gas & Electric	Three load forecasts are developed: a low forecast, based on the CEC's low forecast; a base forecast, based on the CEC's high forecast; and a high forecast based on the CEC's high forecast with additional escalation of 0.3%.
Southern California Edison	Two forecasts: the CEC load forecast and an SCE-developed forecast. The SCE forecast is based on econometric modeling with economic assumptions derived from Global Insights forecasts.

Utility/Regional Planning Authority	Load Forecasting Methodology
San Diego Gas & Electric	Base forecast based on CEC forecast. SDG&E developed its own low and high forecasts which were designed to capture the uncertainty in load, including the uncertainty with overall demand, direct access and Community Choice Aggregation. The high forecast is higher than the CEC high forecast, but was “well within historical forecasting error.” The low forecast also modeled the potential for loss of load to direct access and/or Community Choice Aggregation, and is lower than the CEC low forecast.

4.4 Needs Determination

Resource planning hinges on the utility’s determination of needs over the planning period. Load forecasts are compared to existing and planned resources (including owned generation and contracts) to determine the remaining need that must be met. Thus, inaccurate load forecasts will cause a utility to over- or under-procure resources.

Besides the load forecast and existing resource assessment, two other factors have an important impact on needs determination: (1) reliability planning and the level of reserve margin, and (2) in jurisdictions where applicable, the treatment of direct access load. Each is discussed below.

4.4.1 NON-CALIFORNIA PRACTICE

In most jurisdictions, the focus of reliability planning is on capacity, with reserve margins often set as a straight percentage of system peak with ~15 percent being a typical level of reserve. (In the Northwest, energy may be more important than capacity as the Northwest tends to have an excess of capacity due to its extensive hydro resources.)

The reserve level may be determined by a regional planning entity or through some other method. Georgia Power determined its 15 percent reserve margin based on a study of the cost of Expected Unserved Energy (“EUE”). BC Hydro used a “one-day-in-ten-years” criterion to determine its 14 percent reserve margin.

An alternative to the straight percentage method of reserve margin calculation is exemplified by Idaho Power. In its integrated resource plan ("IRP"), Idaho Power plans for the 70th percentile of an energy forecast and the 95th percentile of a peak demand forecast.

In some cases, a utility or planning entity gives special considerations to local circumstances. Avista Energy set reserves equal to 10 percent of one-hour system peak plus 90MW, with the 90 MW representing specific hydro risk (see Appendix B for details). Seattle City Light and the NWPCC carefully modeled hydro variability through probabilistic analysis, reflecting the high reliance on hydro in those areas (Seattle City Light assumes 100 aMW will be available through market purchases in times of shortfall). Public Service Colorado gave special attention to the possibility that planned resources acquired through bids might not materialize.

Finally, some utilities, including Idaho Power, Puget Sound Energy, and Georgia Power explicitly considered transmission capacity or availability in their needs assessment.

A question in setting reserve margin is how to account for certain types of resources in the calculation. For example, does the level of expected demand reduction due to demand-side management ("DSM") programs get subtracted out of the demand calculation before the reserve is calculated? Public Service New Mexico subtracted energy efficiency, demand response, and customer-owned PV from the demand level before applying its 15 percent planning reserve margin. PacifiCorp subtracted purchases, DSM, and interruptible loads before applying the planning reserve margin.

4.4.2 2006 CALIFORNIA LTPP PRACTICE

In California, PG&E calculated needs on both a 1-in-2 summer temperature demand with 15 percent planning reserve margin, and a 1-in-10 summer temperature demand with 16 percent planning reserve margin (D.04-01-050 requires a load margin of 15-17 percent). Loss of Load Probability ("LOLP") was also considered by PG&E, as described in the Portfolio Analysis and Selection section below. Forecasted amounts of energy

available from hydro sources were based on a normal hydro year. Hydro uncertainty was taken into consideration through the TeVar risk analysis metric described in section 4.10, below.

In California, utilities were required by the CPUC in the 2006 LTPPs to create a low load forecast scenario that assumes customers depart bundled service to take advantage of CCA.⁵³ Thus, in the 2006 LTPP PG&E captured the effect of direct access retail supply through scenario analysis, with one of four scenarios assuming low market prices and low demand, which in turn leads to stranded costs as higher numbers of customers choose direct access or CCA alternatives. Conversely, in the high growth and high market price scenario, the amount of direct access was assumed to be lower than the base case projection from current conditions.

Similarly, in determining bundled service needs, SDG&E measured the potential for loss to direct access and CCA through its low load forecast. In determining system-wide needs, SDG&E, having insufficient information to estimate energy requirements, examined capacity only, based on its role as a Participating Transmission Owner under the CAISO tariff.

SCE calculated its needs determination for its bundled customers separately and determined needs more generally for the entire SP-26 planning area. In the latter case, SCE did not have sufficient information to identify the precise types of resources required, but did attempt to ensure that the regional perspective included a sufficient amount of renewable and conventional resources to meet the needs of the portfolio sought by SCE.

⁵³ CPUC Decision 04-01-050, p.4.

The final decision of the 2006 LTPPs (D.07-12-052) concluded that while estimates of future departing load through CCA and Direct Access are uncertain and difficult to justify, it is not a necessary assumption for analyzing system need. Likewise, the Commission noted that future distributed generation (“DG”) and Municipal Departing Load (MDL) is captured in the historical trends used to develop the IOUs’ forecasts. This means that any cases built from the CEC’s load forecast will include some historic level of DG and MDL already embedded in it. The CPUC decision did not weigh in on how departing load should be treated when evaluating bundled load impacts.

Table 9. Needs Determination Methodologies

Utility/Regional Planning Authority	Needs Determination Methodology
NWPCC	<p>For the NWPCC, the traditional indicator of resource needs has been average energy, but increasing attention is being paid to the region’s capacity to meet various types of peaking requirements. The regional combined peak generation capability is over 50,000 megawatts; much larger than winter peak loads. However, the ability of the hydro system to meet high cold weather loads over a sustained period is limited. The sustained peaking capacity of the hydro system, for example, is 5,400 megawatts less than its nameplate capacity.</p> <p>In assessing resource adequacy, the NWPCC uses GENESYS to probabilistically model the Northwest Power system, considering variations in hydro, weather, and outages. Temperature and precipitation (river flow) variables are modeled in lockstep to reflect the fact that these variables are correlated. The requirement is to meet an LOLP of 5% over the winter period.</p>
PacifiCorp	<p>PacifiCorp considers both capacity and energy in assessing its load-resource balance. PacifiCorp’s planning reserves are calculated as follows: <i>Planning reserves = (Obligation – Purchase – DSM – Interruptible) x PRM</i>. The 2007 IRP considers resource portfolios at 12%-15% reserve levels. PacifiCorp views this percentage range as a prudent and reasonable range for planning purposes when considering both supply reliability and economic impact to customers.</p>

Utility/Regional Planning Authority	Needs Determination Methodology
Idaho Power	<p>Idaho Power calculates its planning reserve margin for 2009 -2011, assuming firm market purchases, to range from 3.5% to 4.6%. In 2012, this margin increases to 17.3% with the addition of new resources. However, Idaho Power does not plan for a specific reserve margin</p> <p>In response to risk exposure during the energy crisis of 2000 and 2001, planning requirements were made more stringent. In lieu of a reserve margin, Idaho Power adopts a 70th and 95th percentile criteria for energy and demand planning, respectively. Existing and committed resources, outages, and transmission capacity are all considered in the analysis.</p>
Puget Sound Energy	<p>Load forecasts are compared to existing supply contracts and contract expirations. Short-term peak needs planning is performed annually, and considers transmission availability.</p> <p>PSE uses reserve margin targets at the pool level, which consists of the Northwest Power Pool territory. The overall pool reserve margin target is 15%. PSE tested capacity pool reserve margins at 0%, 5%, and 15% and found that a pool reserve margin of 15% best mitigated summer price spreads without increasing average prices unreasonably.</p>
Public Service Colorado (Xcel Colorado)	<p>Load forecasts are compared to existing owned generation and supply contracts. Contingency planning is carefully considered, with “backstop projects” planned for the event that planned resources acquired through bids do not materialize.</p> <p>Public Service Colorado uses a 16% planning reserve margin. This value is a placeholder pending the results of a probabilistic study the company is undertaking that will consider the reliability support the company will receive from other utilities in the Front Range of Colorado.</p>
Avista Energy	<p>Confidence interval planning is used to model extreme weather conditions and other variables. A 90th percentile is determined to be the optimal planning criterion. Planning reserves are not directly based on unit size or resource type; rather, reserves are set at a level equal to 10% of the one-hour system peak, plus 90 MW representing specific hydro risk.</p>
Arizona Public Service	<p>Needs are determined every 3 years, with a 15% planning reserve margin.</p>
Nevada Power / Sierra Pacific Power	<p>Derived from demand forecast (including losses) plus reserve margin, less owned or controlled resources and energy efficiency. Generation retirement is considered.</p>

Utility/Regional Planning Authority	Needs Determination Methodology
Public Service Company of New Mexico	<p>Comparison of existing resources to forecast demand, considering reserve margin, and State energy efficiency. Reserve sharing arrangements with other utilities are considered.</p> <p>Consistent with the Case 3137 Stipulation, the E-IRP reflects a PNM reserve margin target of 15% (this is an average target; for any given year the reserve margin is planned within a bandwidth of 12%-20%). For the purpose of this E-IRP, PNM has included in the demand portion of the reserve margin calculation reserves that are projected decrements to load including energy efficiency, demand response and customer owned PV. Reserves are not planned for these resources and they lower the reserves planned based on the load forecast.</p>
Georgia Power Company	<p>Comparison of load forecasts to existing resources, with a 13.5% reserve margin inside of 3 years and 15% reserve margin outside the 3-year window. Transmission capacity is considered. The 15% reserve margin is based on a study of the cost of Expected Unserved Energy (EUE).</p>
Seattle City Light	<p>Comparison of load forecasts to existing resources, taking into consideration the possibility of drought, since SCL is heavily reliant on hydro. Planning is performed for a 1 in 20 low hydro year, with Monte Carlo evaluation to test different load assumptions. SCL plans to meet peak load at a 95% confidence level., with an assumption that 100aMW will be available on the market in times of shortfall.</p>
Northern States Power (Xcel Minnesota)	<p>Load forecasts are compared to owned generation, contracts, planned additions, and projected short-term purchases. NSP considers multiple scenarios and contingencies based on different options pertaining to existing plants, expansion opportunities, etc. Reserve margin is currently 15% (based on the requirements of the MAPP reserve sharing group) but this is expected to decline as a result of NSP joining the Midwest Planning Reserve Sharing Group (PRSG).</p>
British Columbia Hydro	<p>Needs are derived from the demand forecast (including losses) plus reserve margin ("N-1") less existing company owned or controlled resources using an energy balance and capacity balance. BC Hydro calculates that a one-day-in-ten-years criterion requires planning reserves of 14%.</p>
Pacific Gas & Electric	<p>Load forecasts are compared to planned retirements and supply-side resource additions. A 15%-17% planning reserve margin is used. PG&E considers the possibility of varying levels of direct access and CCA load in its scenario analysis.</p>
Southern California Edison	<p>Needs are determined for both bundled service customers and, on a more general level, the entire SP-26 area.</p>

Utility/Regional Planning Authority	Needs Determination Methodology
San Diego Gas & Electric	System-wide (total service area) need for new capacity is estimated based on the CAISO Grid planning criteria. For bundled service customers, capacity needs are determined for both Local Capacity Requirements and System Capacity Requirements.

4.5 Time Period of Resource Planning Analyses

An appropriate planning period is important to the success of utility resource plans. If the planning period is too short, utilities may not be able to recognize benefits of certain resource options that accrue over longer periods; if the planning period is too long, forecasts of the “out” years may be overly speculative and subject to change, reducing the value of any conclusions about those years.

4.5.1 NON-CALIFORNIA PRACTICE

Among the non-California utilities we surveyed, a 20-year planning period was standard. PacifiCorp was an exception on the low end, with a 10-year planning period. Idaho Power recently extended its planning period from 10 to 20 years.

Some utilities attempted to support both a long-term general planning goal and shorter-term procurement review goal by creating a general resource plan that had a longer planning horizon, but with the first years of the plan providing greater detail on near-term procurement decisions. Xcel Energy, in the case of both Public Service Colorado and Northern States Power, used a 40-year modeling period but planned resource acquisition for only the more near term (8 and 15 years, respectively). For Avista Energy, this near-term period was 10 years; Public Service of New Mexico – 5 years; Nevada Power / Sierra Pacific Power – 1-3 years. The NWPCC considered a 5-year focus period for near-term resource adequacy assessment.

4.5.2 2006 CALIFORNIA LTPP PRACTICE

In California, resource planning has focused on the approval of procurement plans. As noted earlier, in California a goal of Long Term Procurement Planning is to create a planning environment that “eliminates the need...for after-the-fact reasonableness reviews” (AB 57, p.2). It is therefore not surprising that the CPUC finds, in D.04-01-050, that “a ten-year procurement planning horizon is appropriate” (p. 93) and that California utility LTPPs are thus based on a 10-year planning period.

Table 10. Time Period of Utility Resource Planning Analyses

Utility/Regional Planning Authority	Time Period of Resource Planning Analyses
NWPCC	20-year planning period with 5-year focus for near-term resource adequacy.
PacifiCorp	10-year IRP period.
Idaho Power	Raised to 20-years from prior 10-year planning period.
Puget Sound Energy	20-year planning period.
Public Service Colorado (Xcel Colorado)	40-year planning period with 8-year Resource Acquisition Period (RAP). 8-year RAP is designed to allow PSCo to learn from the next several years of expected rapid change before committing to resource decisions beyond 2015.
Avista Energy	20-year planning period with focus on first 10 years for resource acquisition.
Arizona Public Service	20 year long-term planning period with 7-year short-term planning period that considers current technologies and purchased power.
Nevada Power / Sierra Pacific Power	20-year planning period required by regulation. 30-year planning period provided voluntarily. Short term (1-3 year) energy procurement plans are also provided.
Public Service Company of New Mexico	20-year planning period with 5-year action plan.
Georgia Power Company	20-year planning period for supply and 10-year planning period for transmission.
Seattle City Light	20-year planning period.
Northern States Power (Xcel Minnesota)	15-year planning period, but 40-year period used for modeling, allowing all costs and benefits of added resources to be taken into account.

Utility/Regional Planning Authority	Time Period of Resource Planning Analyses
British Columbia Hydro	20-year planning period.
Pacific Gas & Electric	10-year planning period
Southern California Edison	10-year planning period
San Diego Gas & Electric	10-year planning period

4.6 Discount Rate

Another important factor in long term planning is the choice of the discount rate used by the utility. Discount rates that are relatively high tend to favor smaller incremental investments due to the stronger impact of relatively large, lumpy investments on utility rates.

4.6.1 NON-CALIFORNIA PRACTICE

Utilities most often base their discount rates on their own Weighted Average Cost of Capital ("WACC"). As shown in Table 11, most utilities for which information was available used discount rates around 7 percent, though the NWPCC and Seattle City Light, which is a municipal utility, used real discount rates of 4 percent and 3 percent, respectively. Some utilities ran sensitivity tests on different discount rates, as noted in the table. Puget Sound Energy takes risk into consideration with regard to its discount rate⁵⁴, but no utilities used differing discount rates in an attempt to reflect the sensitivity

⁵⁴ Puget Sound Energy explains its risk consideration with respect to its discount rate as follows: "PSE's IRP, and our screening of potential resource acquisitions, includes a cost of equity to neutralize the reduction in credit quality from imputed debt for all PPAs. As described previously, the debt rating agencies consider long-term take-or-pay and take-and-pay contracts equivalent to long-term debt; hence there is a cost associated with issuing equity to rebalance the company's debt/equity ratio. Imputed debt in the IRP is calculated using a similar methodology to that applied by S&P. The calculation begins with the determination of the fixed obligations that are equal to the actual demand payments, if so defined in the contract, or 50% of the expected total contract payments. This yearly fixed obligation is then multiplied by a

of a portfolio or investment choice to discount rate; rather, once a discount rate was selected, it was used consistently across all resources.

4.6.2 2006 CALIFORNIA LTPP PRACTICE

Discount rates are not explicitly discussed in the California LTPPs. In its 2007 Integrated Energy Policy Report (IEPR), the CEC recommended that utilities' future fuel costs be discounted "at the 3 percent social discount rate used by the Energy Commission in its standard-setting activities, unless the investor-owned utilities can demonstrate that these costs should be assigned to shareholders" (p.64). Implementing this recommendation would increase the present-value cost of operating natural-gas fired generation, which would in turn improve the relative cost-effectiveness of renewable resources. This recommendation departs from standard utility resource planning practice, described above.

In its 2008 IEPR update, however, the CEC backed down from this position, stating:

The Energy Commission anticipates that the California Public Utilities Commission will require the next round of long-term procurement plans to incorporate risk-based portfolio analysis by reflecting a wide range of future natural gas prices and associated gas price risk... The Integrated Energy Policy Report Committee believes that the planning process is a more direct and transparent method to account for potential gas price risk than the adjustment of discount rates, and recommends that social

risk factor. PSE's current contracts have a risk factor of 30%, a change that occurred in May 2004. Prior to this change, PSE contracts had risk factors between 15% and 40%. Imputed debt is the sum of the present value, using a 7.7% discount rate (the company's current average cost of long-term debt), and a mid-year cash flow convention of this risk-adjusted fixed obligation. The cost of imputed debt is the return on the amount of equity that would be acquired to offset the level of imputed debt to maintain the Company's capital and interest coverage ratios." (p.F-10, F-11).

discount rates should not be used to incorporate natural gas price risks (p.6).

Table 11: Discount Rates

Utility/Regional Planning Authority	Discount Rates
NWPCC	4% real used throughout analysis in principle (because of an error, 4.9% was used in some cases).
PacifiCorp	Pacificorp calculates a rate impact measure when comparing its portfolios, using a 7.1% discount rate across all resources.
Idaho Power	6.93%, after tax. In addition, each of the 4 finalist portfolios in analyzed for sensitivity to changes in discount rate.
Puget Sound Energy	PSE's discount rate is 7.7%, based on the company's WACC. The Quantec study on DSM used in PSE's analysis used a discount rate of 8.4%, also based on WACC. The difference appears to be simply a function of the study having been done at a different point in time.
Public Service Colorado (Xcel Colorado)	7.9%, PSCo's WACC (after tax).
Avista Energy	Not discussed.
Arizona Public Service	Not discussed.
Nevada Power / Sierra Pacific Power	Not discussed.
Public Service Company of New Mexico	Not discussed.
Georgia Power Company	Georgia Power appears to use discount rates consistently across portfolio and test for sensitivity to different discount rates. The actual values were redacted.
Seattle City Light	3% real discount rate used in evaluating portfolios.
Northern States Power (Xcel Minnesota)	NSP uses different discount rates for different perspectives in its Strategist modeling assumptions: customer – 8.18%; real – 5.44%; utility – 7.42%
British Columbia Hydro	A real pre-tax discount rate of 6% is used to estimate the PV of the costs of each portfolio. Sensitivity analysis is also conducted using a discount rate of 8%.
Pacific Gas & Electric	Not discussed

Utility/Regional Planning Authority	Discount Rates
Southern California Edison	Not discussed
San Diego Gas & Electric	Not discussed, since SDG&E's LTPP did not select specific resources to meet the short position. In SDG&E's RFOs, which do select resources, the utility's cost of capital is used.

4.7 Fuel and Electricity Price Forecasting

The comparative economics of a utility's competing portfolios depend in part on the assumptions for fuel prices and, in cases where the utility plans to trade electricity, on electricity market price assumptions. In the evaluation of competing portfolio options that use substantially different fuel inputs, the fuel price forecasts can have considerable effects on the outcome of the analysis. It is therefore important that fuel and electricity price forecasts be as accurate as possible, and that a reasonable range of outcomes are explored to represent alternative futures.

4.7.1 NON-CALIFORNIA PRACTICE

Utilities typically rely, at least in part, on private consultants and published projections for their fuel price forecasts. A common methodology for natural gas price forecasts bases the first few years of forecasted prices on New York Mercantile Exchange ("NYMEX") forward market prices (usually with a transportation or location adjustment), and later years on fundamentals-based forecasts. Northern States Power, for example, took the first 5 years from NYMEX futures and then took a "simple average" of consultant and published reports for years thereafter. Puget Sound Energy also used 5 years of forward prices, then relied exclusively on Global Insight's gas forecast thereafter (the Global Insight forecast was compared to other consultant and publicly available forecasts for "reasonableness.")

Arizona Public Service was an exception, relying more exclusively on forward market prices in its forecast. Arizona Public Service simply used 12-years of NYMEX forward prices and escalated at 3 percent thereafter.

BC Hydro offers another twist. BC Hydro updated previously produced fundamentals-based forecasts by assigning a probability to various cases based on the market history since the time the forecasts were created (see Appendix B for details).

As compared to natural gas forecasts, forecasts for coal, oil, and other fuels tend to rely more heavily on published sources, though private consultant reports are also used. PacifiCorp, Avista Energy, and Georgia Power reference Department of Energy, Energy Information Administration's ("DOE-EIA") studies for coal and/or oil price projections. Nevada Power / Sierra Pacific Power and Public Service Colorado relied on consultant reports for coal and nuclear price forecasts, respectively.

Electric market price forecasts flow from fuel price forecasts, generally by modeling supply conditions and calculating a heat rate for marginal generating units, typically using optimization models such as AURORA. To create a robust electricity price forecast, utilities may use stochastic analysis to determine electric prices under a range of input assumptions, as did Avista Energy.

4.7.2 2006 CALIFORNIA LTPP PRACTICE

In California, Southern California Edison ("SCE") followed a gas forecast methodology similar to that of many utilities we surveyed. SCE blended NYMEX futures with the average of forecasts provided by Global Insight, Petroleum Industry Research Associates ("PIRA"), and Cambridge Energy Research Associates ("CERA"). SDG&E followed a gas forecast methodology similar to SCE, blending NYMEX forwards with fundamental forecasts from public and private sources. PG&E, in contrast, used NYMEX forward prices for the first 5 years, then for the next 5 years used electricity forward prices to estimate natural gas prices, with the ratio between electric and gas prices set by the observed ratio in the final 12 months of gas forwards.

Table 12. Fuel and Electricity Market Price Forecasting Methodologies

Utility/Regional Planning Authority	Fuel and Electricity Market Price Forecasting Methodologies
NWPCC	Excel model of commodity price trends based on past experience, market behavior, and other organizations forecasts – not a supply/demand model.
PacifiCorp	Natural gas based on weighted average of PIRA's low-, medium-, and high-gas-price cases. Coal price forecasts based on the Energy Information Administration's Annual Energy Outlook, with transportation cost adjustment.
Idaho Power	Coal forecasts based on market information, private forecasts, and Global Insight's 2006 U.S. Power Outlook. Natural gas forecasts derived by combining industry forecasts from outside consultants and published sources into a weighted average and adjusting for transportation costs.
Puget Sound Energy	Long-run, fundamentals-based gas forecasts provided by Global Insight, with first 5-years based on forward markets. Price forecasts are developed for six different scenarios representing a range of possible futures.
Public Service Colorado (Xcel Colorado)	Gas and coal forecasts based on a blend of publicly available forecasts, with a transportation cost adjustment. Nuclear price forecasts based on consultants' forecasts. Electric price forecasts based on implied heat rates from gas market prices.
Avista Energy	Gas forecasts based on consultant reports and review of EIA's Annual Energy Outlook. The 2007 IRP is Avista's first to include a daily adjustment of the monthly gas price forecast. Coal forecast based on EIA studies. Electricity prices are forecasted using AURORA with "Monte Carlo-style" analysis to vary input data.
Arizona Public Service	Gas forecasts based on 12-year NYMEX forwards, with 3% escalation thereafter. Coal price projections based on long-term fixed price contracts.
Nevada Power / Sierra Pacific Power	Gas forecast based on the average of market quotes blended with a fundamentals forecast provided by a consultant. The coal price forecast was developed by a consultant.
Public Service Company of New Mexico	Gas forecasts are based on prior (end of 2007) projections, the methodologies of which are not specified.
Georgia Power Company	Gas forecasts developed by Southern Company Services Fuel Services (the methodology is not detailed in the IRP). Oil price forecasts were developed using the EIA's Annual Energy Outlook.
Seattle City Light	Natural gas prices taken from Global Energy Decision's Fall 2007 baseline forecast. Electricity market prices are calculated in AURORA.

Utility/Regional Planning Authority	Fuel and Electricity Market Price Forecasting Methodologies
Northern States Power (Xcel Minnesota)	First 5 years of gas prices are based on NYMEX forwards; thereafter a simple average of the most recent estimates from consultants and publicly available sources is used.
British Columbia Hydro	Based on prior work performed by Global Energy Decision (GED). A Base, Low, and High forecast were taken from the range of previous estimates. Probabilities were assigned to each case as a way to update the forecasts to reflect market developments in the interim, without completing entirely new forecasts.
Pacific Gas & Electric	NYMEX forward prices are used for the first 5 years of the natural gas forecast. For the next 5 years, electricity forward prices are used to estimate natural gas prices, with the ratio between the two determined by the final 12 months of gas forwards.
Southern California Edison	For natural gas, NYMEX forward prices are blended with long-term fundamentals forecasts produced by Global Insight, PIRA, and CERA. For electricity, NYMEX forward prices are blended with long-term electric prices determined from a dispatch model of the WECC area.
San Diego Gas & Electric	Natural gas based on NYMEX forwards from 2007-2010, then blended with the 2011-2016 forecast used in the California Gas Report, which in turn was based on an average of forecasts from the CEC, EIA, and private consultants. Electric prices are based on electricity forwards and implied heat rates from gas forwards.

4.8 Resource Cost Development Methodology

Another important input to resource planning portfolio analysis is the cost assumptions for the various resource options being evaluated. To be meaningful, selecting a preferred portfolio from the set of candidate portfolios – whether on a least-cost basis or on the basis of some other cost hurdle – requires accurate representation of the costs of resource alternatives.

4.8.1 NON-CALIFORNIA PRACTICE

There are two broad approaches to resource cost development: (1) developing costs based on specific, local studies, construction experience, or bids, and (2) relying on published estimates and/or default values in utility expansion planning tools to estimate the costs of proposed resources. Most utilities used a hybrid of the two approaches,

updating generic information to reflect local information where available. PacifiCorp and Public Service New Mexico used Electric Power Research Institute's ("EPRI's") Technical Assessment Guide ("TAG"), customizing or replacing data based on local conditions and knowledge where available. Public Service Colorado, Avista Energy, and Northern States Power used AURORA or the Strategist expansion planning model to estimate costs. In each case, generic model inputs or inputs based on published data were replaced with data based on observation of actual units or RFP responses where such data was available.

BC Hydro took a very detailed approach, updating cost assumptions based on projects planned or underway, or, where no such information was available, undertaking site-specific studies to estimate costs. In contrast, Seattle City Light relied exclusively on Federal, State, and Regional agency reports for supply-side costs.

Nevada Power/Sierra Pacific Power ("NPC/SPPC") is an interesting case. In the past, NPC/SPPC used resource cost development software, such as EPRI's simple object access protocol ("SOAP") to develop cost estimates. This practice was found to produce unreliable cost estimates due to wide fluctuation in commodity and construction costs; in the most recent IRP, cost estimates were based on recent construction experience and by obtaining refreshed cost estimates from manufacturers and/or RFP responses.

Many utilities, including Idaho Power, Avista Energy, Public Service New Mexico, Seattle City Light, and Northern States Power explicitly developed costs for transmission upgrades or interconnections. Northern States Power, for example, based transmission upgrade cost on a 5-year forecast of capital expenditure given average growth over that period.

DSM costs were also explicitly developed by some utilities. In considering DSM, utilities typically developed supply curves for various measures, which were subjected to cost-effectiveness screening based on the utility's avoided costs. Measures that were found to be cost-effective were included in the resource plan. Seattle City Light

considered distribution system benefits resulting from DSM by adjusting downward the DSM cost estimates by an amount proportional to the benefits.

4.8.2 2006 CALIFORNIA LTPP PRACTICE

The resource cost assumptions used in the California IOU's 2006 LTPPs appear to be based on past experience, an assessment of the current market, and RFO responses. San Diego Gas & Electric notes that it used a Market Price Referent ("MPR") price to represent the costs of future renewable power "because it represents a price that would allow renewable power to be ... competitive with other options" (p.176).

Table 13. Resource Cost Development Methodologies

Utility/Regional Planning Authority	Resource Cost Development Methodology
NWPCC	NWPCC staff develops generation cost estimates based on detailed plant specifications and financing assumptions. A number of sources are relied upon, including EPRI, USDOE, NETL, and others.
PacifiCorp	EPRI's Technical Assessment Guide (TAG), recent project experience, and consultant studies are used to develop resource costs. TAG data is customized for each potential site based on local conditions. Based in part on DOE-EIA published information, TAG technology factors and capital cost assumptions were adjusted on the low- and high-end to give an overall range. Quantec consulting constructed supply curves for DSM programs.
Idaho Power	Cost and operating data were derived from the NWPCC, DOE, independent consultants, and regional energy product developers. Levelized cost is calculated assuming baseload and peaking capacity factors. An outside consultant screened transmission options, which were then submitted to the OASIS web site for planners to analyze the necessary upgrades.
Puget Sound Energy	Resource costs are based on adjusted bid prices. Demand resources are screened using PSE's avoided costs and Quantec's cost-effectiveness screening model.
Public Service Colorado (Xcel Colorado)	Strategist expansion planning model used to develop resource costs. Individual resource assumptions based on observation of actual units and/or NREL and EIA studies.

Utility/Regional Planning Authority	Resource Cost Development Methodology
Avista Energy	AURORA modeling with generic inputs replaced where Avista has better local data. Transmission costs modeled through ColumbiaGrid. DSM measures are assumed to be acquired to the extent they are cost-effective, based on surrogate generation costs.
Arizona Public Service	APS develops both a quantitative and qualitative assessment of resource technologies, considering not just the cost of the resource but also factors such as: whether the resource would increase fuel diversity; its impact on reliability; environmental impacts; whether the resource would promote stable electricity prices; indirect costs associated with needed transmission investments, and; integration and operating expenses.
Nevada Power / Sierra Pacific Power	Cost estimates are based on recent construction experience and by obtaining refreshed cost estimates from manufacturers and/or RFP responses. In the past, NPC / SPPC used resource cost development software, such as EPRI SOAP, but this practice was found to produce unreliable cost estimates due to wide fluctuation in commodity and construction costs.
Public Service Company of New Mexico	Costs are derived from EPRI TAG, are modified to fit PNM financial assumptions and local site conditions, and assume PNM will build all facilities. Transmission interconnection costs are considered.
Georgia Power Company	A wide-range of technology options are put through an initial screening, using Busbar screening models to compare the relative costs. According to Commission rules, GPC must issue RFP's to compare bid costs to self-built cost options for any new planned resource block.
Seattle City Light	Derived from Federal, State, and Regional agencies. Transmission costs based on BPA policy. DSM costs based on research from Quantec, an energy consulting firm. DSM costs are reduced to account for distribution benefits
Northern States Power (Xcel Minnesota)	Resource costs for pre-determined additions based on known costs. For other additions, costs are generated by the Strategist expansion planning model. The Production Tax Credit (PTC) for wind generation is assumed to continue through 2015, a key assumption as a large portion of planned generation additions are made up of wind. Transmission upgrade cost is based on a 5-year forecast of capital expenditure given average growth over that period.
British Columbia Hydro	Cost estimates are based on specific studies or local knowledge for each resource type considered. Project lead times, project life, and environmental and social costs are also considered.
Pacific Gas & Electric	Based on an assessment of resource availability, past experience, and RFO responses. Transactions and solicitations are reviewed with a Procurement Review Group (PRG).

Utility/Regional Planning Authority	Resource Cost Development Methodology
Southern California Edison	The resources modeled by SCE are not tied to any specific facilities, and they do not represent any specific technology or existing product. Rather, they are representative of resources that have cost and operating attributes suited to filling specific load requirements.
San Diego Gas & Electric	SDG&E developed a MPR price for future renewable power. The prices were developed assuming a simple average of 10, 15, and 20 year contracts for all generic renewable resources added in a given year. SDG&E selected this price because it represents a price that would allow renewable power to be added a cost competitive with other options.

4.9 Treatment of Energy Efficiency

4.9.1 NON-CALIFORNIA PRACTICE

The utilities we surveyed were divided in their treatment of energy efficiency and other DSM. Two basic approaches were used in roughly equal measure.

Public Service Colorado, Arizona Public Service, Nevada Power/Sierra Pacific Power, Public Service New Mexico, and Northern States Power all determined the level of energy efficiency and other DSM outside of the IRP process. In some cases, as with Public Service Colorado and Northern States Power, minimum DSM levels may have been set by legislative or regulatory mandate. Or DSM levels used in portfolio analysis may have been agreed upon through a public stakeholder process, as was the case with Public Service New Mexico. Three of these five utilities (Public Service Colorado, Arizona Public Service, and Public Service New Mexico) tested multiple scenarios containing different levels of DSM. In every case, the level of DSM had the effect of offsetting the demand and sales forecast, and the IRP planning determined the least cost set of resources given this new level of resource requirement with DSM already accounted for.

Other utilities took a different approach, attempting to model, within the IRP planning process itself, energy efficiency and other DSM on an equivalent basis to supply-side

resources. Generally, utilities following this method, such as Puget Sound Energy, bundled DSM measures into a set of programs or portfolios, based on some measure of cost-effectiveness screening. Cost-effective DSM portfolios were then modeled within the utility's planning software on an equivalent basis to supply-side resources, and were selected according to the criteria used to evaluate the portfolios created in the IRP process.

Whether DSM levels were derived outside the IRP process or through it, utilities generally treated the level of DSM as firm. If DSM was treated as a reduction in load for the purposes of the load forecast, then variability in DSM was accounted for in overall load uncertainty. If DSM levels were derived through the IRP process, utilities relied on a supply curve for DSM measures and programs, based on past experience and studies of DSM potential. The calculated level of DSM is assumed to be equivalently firm to supply-side resources.⁵⁵ In the case of Northern States Power, where the level of DSM was set through legislative mandate, not only was the utility involved in the creation of the legislative target, but it also made serious efforts to determine how the new, much more aggressive level of DSM could be achieved. The utility assumed a graduated transition to the new level of DSM over the planning period, rather than an immediate change.

4.9.2 2006 CALIFORNIA LTPP PRACTICE

In California, the utilities' treatment of DSM in the 2006 LTPPs was largely dictated by the Commission's "loading order," which directs utilities to favor energy efficiency as the first choice for meeting needs, and the commission's targets for energy efficiency,

⁵⁵ Puget Sound Energy indicated that it would probably be more concerned with variability in wind output than variability in the level of DSM savings achieved. (Conversation with Philip Popoff, November 10, 2008.)

which establish specific levels of energy efficiency for each utility. Southern California Edison and San Diego Gas & Electric each provided a candidate portfolio that included the target level of energy efficiency, while acknowledging that this level may be unachievable. In this way, the two utilities were closer to the first group of utilities described above, setting the level of energy efficiency outside of the resource planning process and adjusting load forecasts to reflect the reduced level of consumption. SDG&E included uncertainty in the amount of energy efficiency that would be realized as part of its overall high and low load forecasts.

PG&E's approach was closer to the second group of utilities. PG&E calculated the level of cost-effective DSM that is achievable under each of 4 scenarios used in analysis. The level of energy efficiency varied across scenarios as the avoided costs changed. PG&E used the total resources cost ("TRC") test to determine cost-effectiveness on a level playing field with supply-side resources.

Table 14. Treatment of Energy Efficiency and other DSM

Utility/Regional Planning Authority	Treatment of Energy Efficiency and other DSM
NWPCC	Two separate supply curves are created; one for discretionary resources and another for lost-opportunity resources. The Northwest Power Act directs the NWPCC to give conservation a 10% cost advantage over generation; the NWPCC accomplishes this by adding 10% to the avoided cost estimate when calculating cost-effectiveness.
PacifiCorp	DSM is not included in load forecasts, but rather is modeled on an equivalent basis to supply-side resources. Dispatchable, price-responsive, energy efficiency, and voluntary curtailment programs are all considered.
Idaho Power	DSM is modeled on an equivalent basis to supply-side resources. Residential and commercial program options are based on a study by a consulting firm; industrial options were developed by internal engineering staff. Cost-effectiveness analysis is performed using the methods described in EPRI TAG and the California Standard Practices Manual, considering the Utility Cost Test and Total Resources Cost test perspectives.

Utility/Regional Planning Authority	Treatment of Energy Efficiency and other DSM
Puget Sound Energy	Demand resources are bundled using a portfolio-based avoided cost screening approach. The avoided cost estimates include a “planning adjustment,” reflecting the fact that PSE’s costs are higher than the spot market price for electricity.
Public Service Colorado (Xcel Colorado)	DSM levels are pre-determined according to Commission guidance under three scenarios: a “low” scenario that includes the minimum required to meet Commission mandates, and a “medium” and “high” scenario where the amount of DSM is ramped up to a limit defined by a rate impact cap. Modeling treats energy efficiency as both an offset to load and as a cost.
Avista Energy	In the past, conservation was reflected through a reduction in retail load. Beginning with the 2005 IRP, load is not adjusted downward for conservation, and the conservation resources are displayed separately (equivalent to a supply-side resource). Cost-effectiveness testing is based on avoided costs, with the value capacity contribution being included in the analysis for the first time.
Arizona Public Service	A consultant was hired to estimate DSM potential. Scenario analysis compares incremental increases in energy efficiency to other resource alternatives, but DSM results are not derived using an IRP process.
Nevada Power / Sierra Pacific Power	DSM is approved by the Commission based on the TRC test, with DSM receiving a 5% added return on investment for the analysis. All programs that pass this test are included; i.e. the level of DSM is set outside of the IRP process.
Public Service Company of New Mexico	Regulatory mandate requires specified levels of energy efficiency and other DSM. PNM modeled three levels of DSM which were determined through a publicly vetted potential study, rather than resulting from the IRP.
Georgia Power Company	Economically feasible programs are integrated with and considered on an equivalent basis to supply-side options using the PROVIEW planning model.
Seattle City Light	DSM is not included in load forecasts, but rather is modeled on an equivalent basis to supply-side resources. DSM costs are reduced to account for distribution benefits. A high level of achievable potential is assumed in order to comply with legislative decree.
Northern States Power (Xcel Minnesota)	DSM levels are determined outside of the IRP process and are based on legislative targets. Conservation impacts are subtracted from sales forecasts, which has the effect of lowering the forecasts for peak demand and energy.
British Columbia Hydro	DSM is not included in load forecasts, but rather is modeled on an equivalent basis to supply-side resources.

Utility/Regional Planning Authority	Treatment of Energy Efficiency and other DSM
Pacific Gas & Electric	The level of cost-effective energy efficiency is calculated for each of the scenarios used in PG&E's analysis. In valuing demand-side alternatives, PG&E uses the TRC test, stating that as long as avoided energy and capacity costs are based on market prices, use of the TRC test allows comparison of supply-side resources to demand-side resources on a consistent basis.
Southern California Edison	Sets energy efficiency and other DSM at a level consistent with Commission targets in its "Required" plan, and uses its own forecast levels of achievable DSM in its "Best Estimate" plan. SCE reduces energy forecasts to reflect the presence of efficiency programs, but models demand reductions as a supply-side resource, and peak demand forecasts are not reduced to reflect their presence. A planning reserve adjustment is applied to properly account for demand reduction programs.
San Diego Gas & Electric	SDG&E assumes a level of energy efficiency and other DSM in its portfolio mix that is consistent with Commission targets, although it notes that it may not be able to actually meet these targets. SDG&E subtracts energy efficiency, both committed and uncommitted, from the forecasted load. Demand response programs are split between "pricing driven programs," which are subtracted from load, and "dispatchable" programs, which are modeled as a supply-side resource.

4.10 Treatment of Market Price Uncertainty

In developing the input assumptions necessary for long-term resource planning – load forecasts, fuel price forecasts, other potential costs such as GHG emissions costs – a utility must make guesses about an unknowable future. While the future is unknowable, one thing about it is clear: it will almost certainly not be an exact match of even the best guess or forecast. The method of accounting for potential deviation from forecasts – the treatment of uncertainties – is therefore very important to utility resource planning. In this section we discuss treatment of uncertainty in market price forecasts. Uncertainty around GHG regulation is discussed in section 4.11.

To assess market price risk for input fuels, utilities used either scenario analysis or stochastic analysis, or a combination of the two.

4.10.1 NON-CALIFORNIA PRACTICE

Examples of utilities that treated uncertainty through scenario analysis only include Public Service Colorado, Georgia Power, Northern States Power, and BC Hydro. Northern States Power created scenarios by simply adjusting various fuel prices (independently) upward or downward by 20 percent. Public Service Colorado created a “reasonable” range of gas price forecasts for use in scenario analysis based on its own qualitative assessment of the market, and also tested sensitivity to load and carbon costs through scenario analysis. BC Hydro assigned probabilities to weight base, high, and low gas forecasts in its analysis.

Examples of utilities and planning areas that used a combination of scenario analysis and stochastic analysis to treat uncertainty include the NWPCC, PacifiCorp, Avista Energy, Public Service New Mexico, and Seattle City Light. Each of these utilities created a number of scenarios that represented possible futures. Scenarios may have been defined as simply a mix of conditions (e.g. high gas and electric prices, low load growth, medium RPS levels, low CO₂ adder (PacifiCorp)) or as a series of “what if” questions (what if plug-in hybrid vehicles become commercially available; what if the cost of renewables is much higher than expected (Seattle City Light)). In either case, the scenarios were designed to explore the changes to portfolio economics that resulted from changes in underlying variables.

The method used to augment the scenario analysis with stochastic analysis differed among the utilities we surveyed. PacifiCorp used the scenario analysis to identify a limited set of portfolios for further testing through stochastic analysis. Using the base case scenario, PacifiCorp ran Monte Carlo analyses for each of these portfolios, with random draws of key stochastic variables including load, gas price, electric price, hydro availability, and thermal unit availability. The result was a distribution of outcomes, from which PacifiCorp calculated both the expected PVRR and a measure of risk known as TailVaR₉₅, which takes the average of the worst 5 percent of the Monte Carlo outcomes (again, based on PVRR).

Avista Energy, on the other hand, developed an efficient frontier of cost and risk for multiple scenarios, where cost was represented by PVRR and risk was represented by the standard deviation of cost in a sample year (2017).

Like PacifiCorp, the NWPCC used a TailVaR metric (TailVaR₉₀ in this case) to represent risk. Public Service New Mexico, on the other hand, used the TeVar metric, which takes the cost at a specific point on the distribution, rather than taking the average of the tail of costs. For example, TeVaR₉₅, used by Public Service New Mexico, is the 95th percentile worst outcome, as measured by PVRR.

Stochastic analysis is more computationally sophisticated, but this does not mean it is free from pitfalls. A consultant for Seattle City Light performed stochastic analysis on natural gas prices based on a historical analysis of long-term Henry Hub gas prices. The 75th percentile of the distribution was used to represent a “high” gas price scenario. However, by the time Seattle City Light filed its IRP, gas prices had already reached the upper-end of the distribution forecasted by the consultant based on the historical analysis.

Further, as Avista notes, the resulting level of analysis (Avista simulated 300 hourly iterations or “games” in its stochastic analysis) may be cumbersome. The four stochastic futures Avista created for the IRP required 8,500 hours of central processing unit time and created a 450 gigabyte SQL database.

Utilities may also assess the risk in their forecast of the price of electricity – whether or not they do so may depend on their expected exposure to electricity market prices. Idaho Power, for example, assessed variability in electricity market prices inasmuch as it expected to sell electricity into the market and therefore would be exposed to price variation. Public Service New Mexico, on the other hand, assumed all new resources would be developed within its own electric system and no excess transmission capacity would be available to access purchased power. Electric market price risk was, therefore, not a factor in its analysis.

4.10.2 2006 CALIFORNIA LTPP PRACTICE

PG&E took a two-pronged approach to evaluating market price risk. Risk associated with fundamental shifts in the marketplace was covered through scenario analysis; stochastic risk was analyzed using Monte Carlo simulations of power and gas prices. However PG&E used Monte Carlo analysis not only to analyze stochastic risk, but also to define the scenarios. The scenarios were developed using the results of 3,000 Monte Carlo simulations of the correlated on- and off-peak electricity and gas prices at a *monthly* level using simulation paths that exhibit sustained high prices and sustained low prices. Stochastic risk, or variability *within* a given scenario was estimated by a daily Monte Carlo simulation, using *daily* volatilities and correlations between electric and gas prices.

Southern California Edison and San Diego Gas & Electric each used stochastic analysis to analyze risk. Southern California Edison reported a 99th percentile risk level and San Diego Gas & Electric both a 95th and a 99th percentile risk level.⁵⁶

Where applicable and available, the specific risk metrics used by utilities are included in Table 15 below.

Table 15. Market Price Risk Assessment Methodologies

Utility/Regional Planning Authority	Market Price Risk Assessment Methodology
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⁵⁶ All three California IOUs were required to use TeVaR₉₉ for hedging decisions in D.03-12-062. In D.07-12-052, the Commission adopted TeVaR₉₅ as the primary metric for guiding hedging decisions (pp.177-178).

Utility/Regional Planning Authority	Market Price Risk Assessment Methodology
NWPPCC	Consultants perform statistical analysis using Crystal Ball/Excel based Monte Carlo simulations. Natural gas prices are modeled within the forecast range, including estimates of uncertainty in both long-term trends and seasonal patterns and brief excursions from trends. Hydro variation is also modeled. Periods of electricity price disequilibrium can occur based on imperfect foresight of supply or demand. Statistical analysis is used to represent this eventuality. The TailVaR ₉₀ metric is used.
PacifiCorp	Stochastic simulations were performed for sensitivity analysis and several scenarios address specific risk factors that were identified by the Oregon PUC. The TailVaR ₉₅ metric is used in stochastic analysis.
Idaho Power	Each of the finalist portfolios was evaluated with respect to electricity market sales. (Idaho Power is a net exporter of power under all portfolios, so risk exposure is to declining sales price rather than increasing purchase price).
Puget Sound Energy	Monte Carlo analysis is used to account for four key uncertainty factors, including natural gas prices, electricity market prices, wind generation, and hydro generation. The TailVaR ₉₀ metric is used.
Public Service Colorado (Xcel Colorado)	Sensitivity analysis performed through scenario testing of four key variables: sales, fuel prices, CO2 costs, and inflation. PSCo determined what it felt was the reasonable range of gas and coal prices based on a qualitative assessment of the market. DSM and renewable resource levels were not allowed to change under the different sensitivity tests.
Avista Energy	<p>Monte Carlo analysis is used to test variation in natural gas prices and other key variables. 300 hourly iterations are performed for 2008-2027 using AURORA. The Base Case assumes 30% volatility in natural gas prices and lognormal distribution. Avista develops an efficient frontier to find the optimal level of risk given a desired level of cost and vice versa. Risk for the efficient frontier is measured by the standard deviation of power supply costs in the year 2017.</p> <p>In addition to stochastic modeling, scenario analysis is used to assess change to significant underlying variables.</p>
Arizona Public Service	Not described.
Nevada Power / Sierra Pacific Power	The following variables are considered: natural gas prices, gas supply, gas transportation availability, purchase power prices, WECC-wide resource adequacy.

Utility/Regional Planning Authority	Market Price Risk Assessment Methodology
Public Service Company of New Mexico	Stochastic and scenario analyses are used to determine sensitivities to variation in gas prices and other variables. Stochastic analysis was performed to determine sensitivities to: Load forecast, energy efficiency levels, CO2 price, fuel cost, early retirement of generation facilities due to environmental regulation and RPS compliance. 300 Monte Carlo draws were used and the TeVaR ₉₅ metric is used.
Georgia Power Company	Scenario analysis is used to assess sensitivity to changes in cost of purchased power, fuel prices, and other variables.
Seattle City Light	A consultant performed a stochastic analysis of long-term Henry Hub gas prices to develop a probability distribution, and the 75 th percentile of this distribution is used for the “high” gas price in scenario analysis. In addition, Risk is assessed by stochastic analysis of hydro output, fuel cost, and electricity demand. The TeVaR ₉₅ metric is used.
Northern States Power (Xcel Minnesota)	Scenario analysis adjusts natural gas, coal, and nuclear fuel prices upward and downward by 20%. An additional scenario analysis accounts for seasonal variation by incorporating the costs of hedging tools and natural gas storage into the natural gas price forecast.
British Columbia Hydro	Scenario analysis considers sensitivity to changes in gas price. Base, high, and low scenarios are analyzed based on prior work performed by a consultant. To update the prior forecast ranges to reflect new developments, probabilities are assigned to each scenario and these probabilities are used to weight the forecasts. The TailVaR ₉₀ metric is used.
Pacific Gas & Electric	Risk associated with fundamental shifts in the marketplace is covered through scenario analysis; stochastic risk is analyzed using Monte Carlo simulations of power and gas prices. The TeVaR ₉₅ metric is used.
Southern California Edison	Gas and electricity price forecast confidence intervals were derived by applying stochastic methods that consider long- and short-term parameters for volatility, correlation, and mean reversion. Power and natural gas price volatility is derived using three years of the most recent historical daily forward prices. SCE calculates TeVaR at the 99 th percentile for power price, gas price, load, and supply availability.
San Diego Gas & Electric	Based on the observed volatility in historical data from 2003-2006, SDG&E measures gas and electricity price risk using TeVaR at the 95 th and the 99 th percentile.

4.11 Treatment of Uncertainty in GHG Regulation and Other Environmental Considerations

In recent years, increasing attention on global warming and GHG emissions has given rise to a multitude of proposed legislative and regulatory measures. Substantial uncertainty remains regarding the specific policy instruments, timing, and cost of measures that may ultimately be put in place. The representation of this uncertainty is a challenge of resource planning.

4.11.1 NON-CALIFORNIA PRACTICE

Most utilities in our survey focused on a carbon cost estimate, or range of estimates, to account for uncertainty in GHG and environmental regulation. Some also included potential costs for other emissions such as SO₂ and NO_x. Others considered a range of environmental effects without necessarily assigning explicit cost risk to any, or assigning costs to carbon emissions only. Below, we discuss both the treatment of cost risk around carbon and other emissions, and the utilities' other methods of including environmental considerations in the analysis.

Almost every utility and planning area we surveyed addressed the risk of GHG regulation through scenario analysis, generally assigning a value or range of possible values to carbon emissions and including this cost in the analysis. While some utilities bounded a lower scenario with an assumption of no cost for carbon emissions, many utilities took it as a given that there will be at least some level of carbon emissions cost beginning within the next few years and therefore even their "low" carbon cost scenario included a value for carbon emissions. Estimates tended to cluster in the \$7/ton-\$50/ton range and were based on a review of proposed legislation, and analysis of that legislation, with National Commission on Energy Policy studies, the McCain-Lieberman Climate Stewardship Act, and the Bingaman-Domenici bill being common reference points.

One utility, Avista Energy, used stochastic analysis rather than scenario analysis to address GHG regulation risk. Avista modeled 300 Monte Carlo iterations of carbon cost, with the mean value based on a 2004 National Commission on Energy Policy study.

It is clear that some utilities calculated carbon emissions *levels* for their entire generation mix of both new and existing resources; Puget Sound Energy stated this explicitly, and Public Service Colorado indicated plans to retire four existing coal units as part of its goal to reduce carbon emissions. It is less clear whether, in conducting their analyses, utilities considered carbon *costs* of their entire generation mix, or only evaluated these costs in the context of new candidate resources in their portfolios.

In addition to considering carbon costs as described above, most utilities gave consideration to other emissions in their IRPs, typically including SO₂, NO_x, mercury, and particulates. In some cases, monetary values were assigned to emissions rates based on current or potential regulation; in other cases, such as with Public Service New Mexico, emissions levels were calculated and reported, but no monetary value was assigned.

Utilities and planning entities may also consider environmental effects other than emissions levels in their IRPs. Such consideration may be driven by the particular geographic circumstances of the entity. For example, the NWPCC, which is hydro-power intensive, specifically called out the need to consider the impact on fish populations in planning studies; Arizona Public Service and Public Service New Mexico, both in the arid Southwest, each considered water usage in their resource analyses.

Some utilities have separate environmental documents or committees that are referred to or guide environmental considerations in the IRP. Georgia Power used the Southern Company Environmental Compliance Strategy to address environmental requirements and derive the emissions cost estimates used in its IRP. Seattle City Light's Environmental Policy Statement affirms the importance of environmental considerations to the utility and was a basis for the utility's comprehensive consideration of

environmental effects. Avista Energy's Climate Change Council tracks environmental and GHG issues.

Table 16 below summarizes the treatment of GHG regulation risk and consideration of other environmental effects among the utilities we surveyed.

4.11.2 CALIFORNIA PRACTICE

For the 2006 LTPPs, the CPUC directed the IOUs to "include GHG forecasts as part of their ten year resource plans." Each IOU was to "indicate which methodology and assumptions" it used in making its GHG calculations.⁵⁷

Table 16. Methods of Accounting for GHG Regulation Risk and Consideration of Other Environmental Effects

Utility/Regional Planning Authority	Methods of Accounting for GHG Regulation Risk and Consideration of Other Environmental Effects
NWPCC	<p>A consultant developed 3 scenarios regarding the probability, timing, and magnitude of carbon control measures, based on state experience, workshops, and MIT studies of the McCain-Lieberman proposal. The scenarios were included in the portfolio analysis.</p> <p>Costs of other emission controls and mercury regulation are also included as variables in the portfolio modeling. In addition, the NWPCC proposes to increase consideration of the impact of power operations on fish populations in future planning studies. Climate change will be a key focus of the 6th Power Plan.</p>
PacifiCorp	<p>Portfolios were simulated with scenarios representing 5 different carbon emission cost levels, ranging from \$0/ton-\$61/ton. The IRP considers: currently regulated emissions; climate change; RPS requirements; and hydroelectric relicensing.</p>

⁵⁷ Rulemaking 06-02-013 Assigned Commissioner's Ruling and Scoping Memo, Sept. 25, 2008, p. 24.

Utility/Regional Planning Authority	Methods of Accounting for GHG Regulation Risk and Consideration of Other Environmental Effects
Idaho Power	<p>Emissions adders for CO₂, NO_x, and mercury, assumed to begin in 2012, are included in the overall cost of fossil fuel resources. Scenario analysis tests possible futures for carbon emission costs, with values, derived from a Commission order, ranging from \$0/ton-\$50/ton.</p> <p>The IRP introduces for public discussion questions surrounding green tags and environmental concerns, with the intention of driving to resolution at the Commission level.</p>
Puget Sound Energy	<p>Scenario analysis is used, with the base case assuming \$7/ton starting in 2012, and a high carbon cost scenario assuming \$24/ton starting in 2012. Charges were estimated with reference to a National Commission on Energy Policy report, the EPA's "Clear Skies" initiative, and The Clean Power Act introduced by Sen. Jeffords.</p> <p>Other environmental issues discussed include: policy statement on GHG; PSE overall emissions levels; PSE's goal to reduce emissions rate (goal is to meet the stringent California requirements); extensive consideration of global warming, including local effects. It is not clear that these considerations have any direct effect on the IRP.</p>
Public Service Colorado (Xcel Colorado)	<p>Scenario analysis is used, with carbon prices ranging from \$10/ton-\$40/ton, based on a survey of multiple sources, including EIA and EPA analyses of the McCain-Lieberman bill and other policy reports.</p> <p>Emissions levels also calculated for SO₂, NO_x, particulates, and mercury, with emissions costs assumed for SO₂ and mercury.</p>
Avista Energy	<p>A Climate Change Council tracks environmental and GHG issues. The 2007 IRP focuses on SO₂, NO_x, mercury, and carbon, with emissions costs modeled for each.</p> <p>Carbon emission costs are included in the Base case beginning in 2015 and are based on a National Commission on Energy Policy study. An EPA study of the McCain-Lieberman bill is referenced to quantify the risk of higher carbon costs. Monte Carlo analysis is used to model 300 iterations of carbon costs. Scenario analysis is also used, with one of the scenarios assuming no carbon costs.</p>
Arizona Public Service	<p>APS quantifies the magnitude of emissions and monetizes regulated emissions such as mercury. Water usage is also considered.</p> <p>A \$25/ton carbon tax is used as a stress test in scenario analysis.</p>
Nevada Power / Sierra Pacific Power	<p>Commission approved externality values are added after dispatch, and a Present Worth of Societal Cost is determined for each alternative case. CO₂ is modeled as a carbon tax.</p>

Utility/Regional Planning Authority	Methods of Accounting for GHG Regulation Risk and Consideration of Other Environmental Effects
Public Service Company of New Mexico	<p>Emission levels for commonly considered emissions such as SO₂ and NO_x are calculated, but only CO₂ emissions are considered in the modeling. GHG regulation risk is addressed through scenario analysis, with carbon costs ranging from \$8/ton-\$53/ton.</p> <p>PNM also considers water usage when assessing resources.</p>
Georgia Power Company	<p>Sensitivity analysis addresses emissions including SO₂ and CO₂. Carbon emissions are modeled in scenario analysis as a tax. The company's Environmental Compliance Strategy addresses environmental requirements and helps guide assessment of environmental factors in the IRP.</p>
Seattle City Light	<p>The company's Environmental Policy Statement and Vision, Mission, and Values Statement affirm the importance of considering environmental impact, which is explicitly taken into account in the IRP process as it is one of four criteria used to evaluate the portfolios. Air emissions, including CO₂, SO₂, NO_x, mercury, and particulates are estimated, with a cost applied to approximate the value of complying with potential future environmental regulations. The methodology for deriving these costs and treating uncertainty in the values is not discussed. Because SCL is essentially already required by law to meet growth with renewable resources, GHG cost assumptions have little impact on the final analysis.</p> <p>Other environmental effects, including those on land use, water, soil, wildlife, employment, recreation, and aesthetics, are assessed for each portfolio considered. SCL updates an Environmental Impact Statement of new resource portfolios.</p>
Northern States Power (Xcel Minnesota)	<p>GHG regulation risk is addressed through scenario analysis, with carbon charges beginning in 2010 and ranging from \$9/ton-\$40/ton, based on publicly available analyses of existing and proposed greenhouse gas policies.</p> <p>NSP includes other environmental externality costs as required by Commission order, assuming a cap and trade permit systems for SO₂, NO_x, and Mercury, consistent with the U.S. EPA Clean Air Interstate Rule. NSP also plans to decommission certain plants in order to improve the company's overall emissions profile. NSP has a 5-year environmental action plan.</p>
British Columbia Hydro	<p>A consultant created 3 scenarios based on regulatory policy targets and the flexibility of compliance mechanisms. Prices range from CND \$14/ton in the near-term to CND \$300/ton in 2020.</p> <p>U.S. RPS legislation and an estimation of the market effects of trading renewable energy in the U.S. are considered. "Social license to operate" evaluation considers air emissions. Risk and mitigation discussions include environmental issues, construction, transmission delays.</p>

Utility/Regional Planning Authority	Methods of Accounting for GHG Regulation Risk and Consideration of Other Environmental Effects
Pacific Gas & Electric	Pursuant to Commission order, a GHG adder is included in Long-Term Request for Offer (LTRFO) bids (\$8/ton in 2004, escalating at 5% per year).
Southern California Edison	Pursuant to Commission order, a GHG adder is included in Long-Term Request for Offer (LTRFO) bids (\$8/ton in 2004, escalating at 5% per year).
San Diego Gas & Electric	Pursuant to Commission order, a GHG adder is included in Long-Term Request for Offer (LTRFO) bids (\$8/ton in 2004, escalating at 5% per year).

4.12 Portfolio Development

To conduct meaningful long-term resource planning, utilities construct different portfolios, each made up of a combination or mix of resources, for comparison against cost and other metrics. Utilities may either manually create a set of portfolios to meet certain criteria, or use a software planning expansion tool, such as the Strategist expansion planning tool, to create portfolios. Often a mix of the two methods is employed, with the utility specifying levels of certain pre-determined resources and using the modeling tool to fill in the remainder.

4.12.1 NON-CALIFORNIA PRACTICE

In all, six utilities built their candidate portfolios (with or without stakeholder input) purely “by hand;” seven used expansion planning models.

The number of portfolios analyzed was very different under the two methods. Where optimization models were used, a very large set of portfolios was evaluated. The NWPCC evaluated 1,400 portfolios and Northern States Power indicated that “thousands” of different resource combinations were analyzed by its expansion planning model to arrive at least cost plans under each scenario. Public Service New Mexico noted that each of its 27 scenarios was further divided into 3-5 energy efficiency cases, and that modeling the resulting 90 or so scenarios/cases generated up to 5,000

portfolios per case, implying analysis of up to 450,000 portfolios. Though unspecified by other utilities using expansion optimization tools, the number of portfolios considered was also likely in the hundreds or thousands.

Clearly it would be prohibitively complex to develop a similar number of portfolios by hand. Where portfolios were developed by hand, the numbers among the non-California utilities we surveyed ranged from a low of five to a high of 24.

The reason for developing all or part of a portfolio “by hand” is usually to force inclusion of certain resources that are necessary or desired for non-economic reasons. In some cases, the utility may be severely constrained by regulatory or legislative mandate. For example, because Seattle City Light must meet 15 percent of its load through new, renewable resources by 2020 (and hydro, which makes up 90 percent of current generation is not eligible) the utility is de facto limited in its expansion choices to 100 percent renewable resources. Similarly, Puget Sound Energy and Northern States Power manually selected renewable resources sufficient to meet RPS standards (allowing the planning expansion tool to choose the rest).

Arizona Public Service selected portfolios by hand, but for a slightly different reason. In this case, each portfolio explored a particular type of resource in isolation, with the goal of providing a simplified comparison of available resource choices, which could then be used to guide decision-making. BC Hydro employed a stakeholder process to identify candidate portfolios.

4.12.2 2006 CALIFORNIA LTPP PRACTICE

In California, utilities are also limited in their resource options. The Energy Action Plan jointly adopted by the CPUC, CEC, and CPA, specifies the preferred loading order of new resources. The mandating of energy efficiency targets and RPS standards set minimum levels for each of these resources. State limits on GHG emissions rates effectively eliminate conventional coal as a resource option. Thus, much of the task of portfolio creation is simply an act of “following the rules.” The universe of feasible

options to meet any remaining need may be small. This may in part explain the smaller number of portfolios considered by the California IOUs. PG&E developed three portfolios; Southern California Edison two. San Diego Gas & Electric developed three portfolios, one each for high, base, and low needs scenarios. These portfolios were further delineated to test for changes in local resource needs due to uncertainty in new transmission. SDG&E describes only the preferred portfolio in its LTPP.

Table 17. Portfolio Development Methodologies

Utility/Regional Planning Authority	Portfolio Development Methodology
NWPCC	Portfolios are developed using Olivia (a program produced by NWPCC for managing and storing portfolios that are analyzed with OptQuest and Crystal Ball software) and Excel. 1,400 portfolios were tested. To reduce computational complexity, the NWPCC uses quarterly summaries of key variables, rather than hourly data.
PacifiCorp	A resource expansion optimization tool known as the Capacity Expansion Module is used to screen and develop portfolios. The CEM considers a multitude of portfolio plans and selects the optimal portfolio for each scenario considered. From this broad analysis, PacifiCorp selected 12 portfolios for further testing, and 5 additional portfolios designed to address new and evolving regulation.
Idaho Power	Examined 12 portfolios that were designed to explore a variety of different resource alternatives, including; predominantly coal fired with almost no natural gas; no coal and 1,000 MW of new renewable, and; 1,475 MW of new transmission import capacity, among others.
Puget Sound Energy	First screened resources individually; only resource types that were pre-determined as being viable for the service area were considered. Minimum levels of RPS to meet standards levels were manually included. Then, began with 24 integrated supply and demand portfolios for screening. This screening led to selection of 12 portfolios that were tested for risk. Feedback loops identified additional questions, which then led to the development of additional portfolios.

Utility/Regional Planning Authority	Portfolio Development Methodology
Public Service Colorado (Xcel Colorado)	Largely dictated by Commission rules, which require evaluation of three portfolios: a Base with minimum required levels of DSM and renewable; a Medium case with increasing amounts of these resources; and a High case, with the maximum amount of these resources achievable subject to a 2% retail rate impact cap. The Strategist model is used to create least cost portfolios for each of these scenarios; thus a multitude of potential portfolios is considered.
Avista Energy	Modeled by AURORA with, under some scenarios, constraints for meeting RPS standards, subject to 4% impact on utility revenue requirement.
Arizona Public Service	Five portfolios are selected based on judgment of resource planning personnel. The portfolios compare several prominent resource alternatives (natural gas, renewable resources, nuclear resources, coal resources and energy efficiency resources) and are designed to provide a simplified comparison of the available resource choices by illustrating each resource choice in isolation.
Nevada Power / Sierra Pacific Power	Developed by the utility with limited input from stakeholders.
Public Service Company of New Mexico	A list of resources is developed through stakeholder meetings, subject to limitations based on fuel supply constraints or technical constraints. Twenty-seven scenarios were developed through the stakeholder process and PNM's modeling yielded several hundred to several thousand resource portfolios for each of the 27 pre-defined scenarios.
Georgia Power Company	Potential technologies are identified and put through a detailed screening process. Technologies that pass are further evaluated using PROVIEW to create the optimal mix under various scenarios. Economically feasible DSM programs are integrated into the supply plan using PROVIEW.
Seattle City Light	Portfolios are manually constructed in AURORA, subject to constraints imposed by recent legislation and with further constraints put in place with the intent of meeting a set of stated policy objectives. The first round of analysis considered 6 portfolios. Analysis led to the creation of 6 new portfolios for a second round of analysis.
Northern States Power (Xcel Minnesota)	Largely driven by recent legislative activity, which mandates high levels of renewable resources (particularly wind) and DSM, as well as restricting overall carbon emissions. Subject to these constraints, the remaining resource mix is determined by the Strategist model. Thousands of different resource combinations were considered by the Strategist model.

Utility/Regional Planning Authority	Portfolio Development Methodology
British Columbia Hydro	17 portfolios were manually developed through a stakeholder process with the goal of reaching pre-defined criteria. Supply curves that BC Hydro develops for each resource type are used to help develop the portfolios.
Pacific Gas & Electric	Portfolios are manually developed with particular consideration to portfolio “fit” based on how well a particular resource provides the power products that need to be added to the portfolio. Three portfolios are developed to highlight the tradeoffs between reliability, environmental stewardship, and cost.
Southern California Edison	SCE creates two candidate portfolios by hand, with the intent of exploring differing levels of DSM and renewable resources. In each case, SCE builds the portfolio in accordance with “loading order,” first including DSM, followed by renewables, and ultimately meeting remaining need on a least-cost basis.
San Diego Gas & Electric	SDG&E adds resources to its portfolio in the order outlined in the “loading order.” The quantities of many of the resources are predetermined by the Commission in other proceedings or by State law. SDG&E describes the range of need for its candidate portfolio, given the uncertainty in the load and whether major transmission is added between SDG&E and surrounding systems. SDG&E describes only one candidate portfolio – the Preferred Plan.

4.13 Portfolio Analysis and Selection Criteria

The purpose of developing competing portfolios via resource planning is to find a preferred portfolio deemed to offer the best mix of resources given a range of potential futures. The fundamental criterion for portfolio comparison is cost, with PVRR as the standard measure of cost used by all the utilities. Many utilities considered other measures of cost as well, such as rate impact, or capital costs only, but when it came to the final evaluation of cost, PVRR was the measure of choice.

A second fundamental criterion is risk. Risk may be analyzed through scenario and sensitivity analysis – that is, through comparison of discrete changes to underlying variables; or through stochastic analysis which looks at a distribution of possible outcomes, based on the combination of distributions of underlying variables. Most

utilities used a combination of the two (we discuss the stochastic treatment of risk in section 4.10, above).

4.13.1 NON-CALIFORNIA PRACTICE

The number of scenarios or sensitivities considered varied widely. Among the non-California utilities we surveyed, three or four scenarios represented the low end and 16-30 or more represented the high end (see Table 18, below, for the number by utility, where available). Where utilities defined scenarios as particular states of the world and attempted to change all variables in concert to represent that future world state, the number tended to be lower. Where utilities created scenarios that might be referred to instead as sensitivities – testing a range of states by adjusting individual variables upward and downward – the number tended to be higher. The NWPCC was an outlier, testing 750 unique “futures.”

Outside of cost and risk, the selection criteria nominated by utilities varied widely, and included the following:

- Rate impact
- Rate stability
- Fuel diversity
- Flexibility
- Public/stakeholder input
- Must be at least 4th most cost-effective (least cost) portfolio
- No coal without carbon capture and sequestration
- Exposure to electricity markets
- Resource (plant) cost only, not total cost

- Environmental concerns, energy efficiency or RPS requirements, and/or state environmental objectives
- Shareholder value

Reliability was also a consideration, of course. In most cases, however, it is more of a pre-requisite to the candidate portfolios than a measure of them.

Evaluation of the portfolios according to the criteria above can range from the highly quantitative to the much more subjective, and even to ultimately not selecting a preferred portfolio at all. On the more quantitative end of the scale, Avista Energy used a combination of linear programming and Monte Carlo analysis to develop an efficient frontier, based on expected cost and standard deviation of cost in a test year. A preferred risk/cost balance was determined (through an unspecified method) and Avista developed a plan as close as possible to the portfolio on the efficient frontier compatible with this risk/cost balance. This reliance on quantitative methods does not imply an absence of management judgment, however; Avista notes that several constraints to the PRiSM (Preferred Resource Strategy Linear Programming Model) inputs “were necessary to ensure the PRiSM model selected a reasonable portfolio.”

Idaho Power, in contrast, evaluated its 12 manually-developed portfolios under four scenarios that varied CO₂ and gas prices, based on criteria that included market exposure and measures of costs. Four finalist portfolios were then subjected to additional risk assessment through scenario analysis. However, no weighting or metric was used to rank the finalist portfolios; rather, public and stakeholder input, along with a consideration of risk, were used to select the preferred portfolio. Arizona Public Service, similarly, tested portfolios for sensitivity to key variables and presented the results to stakeholders and the Commission for feedback.

Puget Sound Energy and Public Service Colorado both calculated the costs of various portfolios using scenario or Monte Carlo analysis to assess the risk of changes in

underlying variables. But while cost and risk were measured and were important factors in portfolio selection, this ultimately was not the basis on which the decision was made. Puget Sound Energy found that the least cost analysis revealed small difference and variance across scenarios, freeing it to make a final determination based, at least in part, on qualitative factors. Public Service Colorado noted a recent Commission planning rule change from “least cost” to “cost effective,” and thereby chose a “cost effective,” but not least cost, portfolio that it found to be most in-line with its own and the State’s environmental and utility planning objectives.

4.13.2 2006 CALIFORNIA LTPP PRACTICE

Each of the three California utilities took into consideration cost, reliability, and environmental benefits, among other factors, in evaluating candidate portfolios. Of two candidate plans described, SCE chose the lower cost “Best Estimate Plan” over the Commission “Required Plan,” because the “Best Estimate Plan takes a measured approach that yields the lowest cost to SCE’s customers while maintaining system reliability, achieving procurement goals and achieving realistic levels of demand-side management” (p.111). The Required Plan is found to be unfeasible and “suffers from several grave flaws which make it less than optimal” (p.5).

PG&E describes three plans that “highlight trade-offs between reliability, cost and environmental impact” (p.VI-12). PG&E chooses the higher cost Increased Reliability and Preferred Resources Plan because it deems the plan represents “a reasonable cost trade-off” to provide enhanced reliability and reduction in air emissions, and supports the “clear policy direction of the Governor, Legislature, and Commission for California to be a world leader on environmental issues by procuring additional renewable and preferred resources” (p.VI-14).

SDG&E chooses among plans representing responses to differing levels of load growth – high, base, and low – noting that because of policy constraints on resource choices, the “key trade-offs for SDG&E in this LTPP is to assess what resources should be added to

maintain grid reliability” given uncertain load and other factors (p.176). SDG&E chooses a plan that builds capacity earlier, finding that “in the worse case, the capacity added in the 2008 – 2009 period is just capacity that would need to be added by 2010 anyway” (p.179).

Portfolio analysis and selection criteria are summarized by utility in Table 18, below.

Table 18. Portfolio Analysis and Selection Criteria

Utility/Regional Planning Authority	Portfolio Analysis and Selection Criteria
NWPCC	<p>Crystal Ball Monte Carlo simulation is used to derive a cost distribution of portfolios across 750 “futures.” Crystal Ball OptQuest optimization module determines the least cost portfolio for a given risk level to develop an efficient frontier. Cost is measured as the net present value of total system costs, and the overall approach is described as “risk-constrained, least-cost planning.”</p> <p>NWPCC does not select a single optimal cost-risk point on the efficient frontier. Instead the NWPCC offers the analysis and supporting models to Pacific Northwest utilities to assist in the development and evaluation of their individual resource plans.</p>
PacifiCorp	<p>The Planning and Risk (PaR) Module is used for detailed production cost simulation and associated stochastic analysis. 16 initial scenarios are considered to identify robust resources – those that frequently appear in the model’s optimized portfolios under a range of futures. Using the results of scenario analysis, risk analysis portfolios are defined for stochastic simulation. The preferred portfolio is selected from among the risk analysis portfolios on the basis of cost (PVRR), rate impact, and risk balance across 5 CO2 adder levels that varied from \$0 - \$61/ton.</p>
Idaho Power	<p>Manually developed portfolios were analyzed using AURORAxmp. Each portfolio was analyzed under 4 different scenarios that varied CO2 and natural gas prices. Portfolios were ranked according to the following criteria: (1) a measure of the portfolio’s reliance on and exposure to the market; (2) the present value of the average total cost (which includes market sales and purchases); (3) the present value of the resource cost (does not include market sales and purchases). Four of the original 12 portfolios were thus identified for additional risk assessment through scenario analysis. No specific metric or weighting of the different risk measures was used to rank the finalist portfolios. Rather public and stakeholder input, along with consideration of the risk measures, were used to choose a preferred portfolio.</p>

Utility/Regional Planning Authority	Portfolio Analysis and Selection Criteria
Puget Sound Energy	<p>A mix of AURORA modeling and common sense adjustments, the portfolio analysis was conducted with the intent of investigating several key questions and/or tradeoffs through the creation of 6 scenarios, such as “what is the impact if carbon sequestration technology can not be proven viable?” Monte Carlo analysis was used to further evaluate risk and volatility. Selection was based on least expected net present value cost. However, PSE recognizes that quantitatively, the least expected cost calculations result in small differences and variance across scenarios. Qualitative considerations help make the final selection, with an evaluation of risk given alternative futures.</p>
Public Service Colorado (Xcel Colorado)	<p>Strategist expansion planning model used to optimize a least-cost balance of resources that meets the DSM and renewable requirements in each of the portfolios. 3 scenarios are evaluated, representing differing levels of required energy efficiency and renewable resources, and additional sensitivity analysis tests sensitivity to key variables.</p> <p>An emergency rulemaking of the Colorado PUC recently modified resource planning rules from “least-cost” to “cost-effective.” PSCo’s evaluation considers the (PVR) cost of each portfolio under different sensitivity assumptions and while the “numbers” are taken into consideration, the decision is ultimately based on an assessment about which choice best meets the State’s and PSCo’s environmental and utility planning objectives.</p>
Avista Energy	<p>AURORA Monte Carlo iterations are used as inputs to Avista’s proprietary linear programming model, PRiSM. Efficient frontier developed to compare risk minimization to cost minimization, with cost measured by total cost NPV and risk measured by standard deviation in a test year. Avista selects a risk/cost balance of 25/75 along the efficient frontier. This is the basis for the preferred portfolio; however, because the portfolios created in AURORA are “smooth” whereas actual utility procurement is “lumpy” the final preferred portfolio lies slightly off the efficient frontier. Management judgment is also a factor. Several constraints to the PRiSM inputs “were necessary to ensure the PRiSM model selected a reasonable portfolio.” The analysis is repeated across 4 scenarios representing possible future worlds.</p>
Arizona Public Service	<p>Scenarios are simulated using APS’s production cost model to assess the cost (cumulative present worth (CPW) of the revenue requirement) and sensitivity to changes in key risk factors (natural gas and CO2 prices). APS has not selected a specific portfolio at this point in the process, but rather presents the results of its analysis to the Commission and stakeholders for feedback.</p>

Utility/Regional Planning Authority	Portfolio Analysis and Selection Criteria
Nevada Power / Sierra Pacific Power	PROMOD IV, capital expense recovery software, and qualitative factors are used to assess the merits of each portfolio. Portfolios are tested for sensitivity to changes in load forecast, fuel prices, and purchase power prices. Portfolios are selected based on least cost, risk mitigation, rate stability, reliability, and other qualitative factors.
Public Service Company of New Mexico	27 scenarios were created through a stakeholder process, and each is further divided into 3-5 energy efficiency cases. Scenario and stochastic analysis is used to test portfolio sensitivity to load, gas price, carbon price, and specific resource restrictions. Selection criteria include cost ("least cost 20-year portfolio"), reliability, energy efficiency and renewable energy compliance, environmental effects, fuel diversity, and flexibility, with greatest weight apparently given to cost, carbon reduction, and reliability.
Georgia Power Company	The PROVIEW planning model is used to create least cost portfolios under various scenarios with changes to load, outage rate, DSM, carbon price and other emissions costs, and fuel prices. At least 30 scenarios/sensitivity cases were considered. Selection criteria include flexibility, reliability, environmental impacts, risk, and stockholder value.
Seattle City Light	6 portfolios were evaluated against existing resources plus spot market purchases only. Based on results, a second set of portfolios was created and evaluated across four scenarios that test alternate futures agreed upon by stakeholders. These final portfolios were quantified and ranked against a set of measures designed to allow comparison across the following criteria: provide reliable service; minimize cost to customers (20-year NPV of portfolio costs); manage risks; minimize environmental impacts.
Northern States Power (Xcel Minnesota)	NSP creates a reference case, which assumes minimal expansion of existing resources. Resource additions in the reference case are determined by Strategist. To this reference case are compared several alternative scenarios that involve expansion of existing utility resources and contracts. Sensitivity analysis is performed to compare the cases over different underlying assumptions regarding load, fuel costs, CO2 cost, other externality cost, and capital cost escalation. Subject to renewable energy constraints, DSM constraints, etc. NSP chooses the portfolio with the lowest PVRR. This portfolio was found to be robust across the sensitivity analyses.
British Columbia Hydro	A portfolio trade-off analysis tests portfolios against criteria, including: resource mix, DSM, supply security, and specific local plant considerations. Sensitivities are tested to market prices, emissions costs, regulatory developments, stakeholder interests, and DSM uncertainties. Portfolio selection is based upon reliability, cost (PV of incremental cost), and environmental risk.

Utility/Regional Planning Authority	Portfolio Analysis and Selection Criteria
Pacific Gas & Electric	PG&E examines its 3 candidate portfolios under 4 scenarios. While the candidate portfolios are designed to examine trade-offs between reliability, environmental stewardship, and cost, the scenarios are designed to explore the candidate portfolios' performance under changing assumptions in load, fuel cost, and direct access participation. Criteria used in analysis include: reliability (LOLP and LOLE); compliance with state environmental goals or requirements; cost; risk; and GHG emission level. The preferred plan is selected because it provides increased reliability and preferred (environmentally friendly) resources at only modestly higher cost.
Southern California Edison	To analyze cost, SCE measured the total revenue requirement across candidate plans and scenarios. Costs were compared across all confidence levels. SCE measured Expected Energy Not Served (ENS) to assess reliability. To measure environmental impact, SCE considered (a) a stochastic analysis of emissions, (b) the ability to meet RPS goals, (c) levels of demand response, and (d) the amount of energy efficiency. SCE finds that the preferred plan results in lower costs under all scenarios and at all confidence levels and has superior reliability. While the plan not chosen results in lower CO2 emissions, the extra cost is deemed excessive.
San Diego Gas & Electric	SDG&E builds portfolios to meet load under three scenarios related to its high, medium and low load forecasts. SDG&E qualitatively assesses the relative merits of adding resources to meet each load level. Since many of the resources are pre-determined and since the LTPP only addresses need and does not select resources, SDG&E is essentially deciding only on the timing and location of resource additions. SDG&E recommends that a plan be selected not just based on expected conditions, but one that can cover various uncertainties. SDG&E selects a plan that adds capacity sufficient to meet the high load scenario. SDG&E determines that even in the low cases, this capacity is needed only 2 years later, and that therefore it is preferable and not excessively costly to plan for the high case.

4.14 Stakeholder Process

The majority of utilities surveyed employed some type of stakeholder process. The types of stakeholders included in various utilities' processes included, among others: customers; native populations; conservation and renewable resource advocates; environmental groups; project developers; other utilities, and; Commission staff and other government agencies.

Often stakeholder involvement was coordinated through a committee or other organization. These organizations may be the result of regulatory or legislative mandate (for example the Integrated Resource Plan Advisory Group (“IRPAG”) and Conservation Resource Advisory Group (“CRAG”) of Puget Sound Energy) or they may be formed voluntarily by the utility (which appears to be the case with Avista Energy’s Technical Advisory Committee. Most utilities held multiple public meetings with the involvement of their stakeholder groups.

Among utilities that were not explicit about stakeholder involvement, at least two, Public Service Colorado and Northern States Power, were quite constrained in their resource options due to regulatory and/or legislative mandate. The fact that many resource issues had already been addressed through the public process of law- or rule-making may partly explain the reduced focus on stakeholder involvement in the IRP process.

Utilities most commonly file IRPs every two or three years.

Table 19. Processes Used in Integrated Resource Planning

Utility/Regional Planning Authority	Process Used in Integrated Resource Planning
NWPCC	The NWPCC was established by the 1980 Pacific Northwest Electric Power Planning and Conservation Act, and is required to develop 20-year power plans at least every 5 years. Power plans are developed through a public process that begins with issuance of a paper and request for comments. Further papers with more detailed plans are then developed for public review and comment. Next a Draft power plan is released for public review and comment. And finally, after review of comments, the final plan is adopted.
PacifiCorp	The planning process begins with a review of the planning environment, followed by an update of inputs and assumptions, and proceeding through needs assessment, candidate resource list development, and portfolio analysis and selection, as described in this report. Public/stakeholder involvement does not appear to be an explicit part of the process.

Utility/Regional Planning Authority	Process Used in Integrated Resource Planning
Idaho Power	Idaho Power enlists the assistance of customers in developing the IRP through an advisory council which represents the interest of the customer base; participates in issues discussions; and helps develop ways to engage the public-at-large in the process.
Puget Sound Energy	Seven formal Integrated Resource Plan Advisory Group (IRPAG) meetings, five Conservation Resource Advisory Group (CRAG) meetings, and dozens of informal meetings and communications preceded the filing of the IRP. The IRPAG and CRAG are made up of a variety of stakeholders and many of the meetings are open to all comers.
Public Service Colorado (Xcel Colorado)	The process is largely driven by regulatory mandate, which requires that PSCo provide emissions estimates; analyze 3 specific portfolio mixes; and report plans for complying with the Renewable Energy Standard.
Avista Energy	Avista actively seeks input from constituents. The company sponsored 5 meetings of a Technical Advisory Committee (TAC) made up of stakeholders. The TAC provided significant input on modeling, planning assumptions and the general direction of the planning process.
Arizona Public Service	Currently, there is no formal resource planning process in Arizona. The Arizona Public Utilities Commission is currently engaged in a resource planning workshop process, which APS is confident will result in formal rules that will define a resource planning process.
Nevada Power / Sierra Pacific Power	Regulation allows for pre-IRP filing meetings with the Commission staff and Bureau of Consumer Advocacy and DSM programs are developed through collaboration with stakeholders. Outside of the above, there does not appear to be a great deal of stakeholder involvement. . However, DSM programs are developed through collaboration with stakeholders.
Public Service Company of New Mexico	PNM has an open stakeholder process, with stakeholder input utilized in every part of the resource planning process. PNM held 16 stakeholder meetings in the process of developing its IRP, and is required to file every 3 years.
Georgia Power Company	Participation by non-utility entities in the selection of supply-side and DSM resources appears to be limited.
Seattle City Light	The two-year planning process included stakeholder involvement and recruiting of expertise from within and outside the utility. The IRP stakeholder committee represents residential, commercial and industrial customers, environmental organizations, power resource developers and energy related government agencies. This committee guided resource planning efforts during five meetings with comments, questions and suggestions throughout the process. Members of the public also attended IRP public meetings and offered suggestions that helped to shape the analyses used in the planning process.

Utility/Regional Planning Authority	Process Used in Integrated Resource Planning
Northern States Power (Xcel Minnesota)	The plan takes significant direction from the Minnesota legislature, which has recently enacted laws requiring: a renewable energy standard; annual energy conservation goals, and; GHG reduction goals. As a result of these laws, NSPCo may not build, import, or enter into a long-term contract for any power that would increase GHGs on a statewide basis, and must use a carbon value of \$4 - \$30 in its analysis.
British Columbia Hydro	First Nations (a term of ethnicity that refers to the Aboriginal peoples in Canada who are neither Inuit nor Métis people) and other stakeholder input into the portfolio construction process came from Provincial Integrated Electricity Plan Committee (PIEPC) members.

4.15 Software

Though some utilities develop their own internal models, most use some form of commercially available software to forecast loads, calculate production costs, optimize resource alternatives, or simulate electric markets. As shown in Table 20, below, the Strategist model and PROMOD IV, both by Ventyx, and AURORAxmp, by EPIS, Inc., were commonly used choices.

Table 20. Software Used in Integrated Resource Planning

Utility/Regional Planning Authority	Software Used in Integrated Resource Planning
NWPCC	AURORAxmp for demand growth in other western areas. The NWPCC GENESYS probabilistic model for modeling generation in the Pacific Northwest. Crystal Ball Monte Carlo and OptQuest Excel add-ins for risk analysis and optimization. Olivia Olivia (a program produced by NWPCC for managing and storing portfolios that are analyzed with OptQuest and Crystal Ball software) and Excel for tracking portfolios and performing portfolio analysis.
PacifiCorp	Capacity Expansion Module for resource expansion optimization. Planning and Risk Module to develop risk-adjusted portfolio performance measures.
Idaho Power	AURORAxmp

Utility/Regional Planning Authority	Software Used in Integrated Resource Planning
Puget Sound Energy	AURORAxmp Portfolio Screening Model (Excel based, internally developed)
Public Service Colorado (Xcel Colorado)	Strategist
Avista Energy	AURORAxmp PRISM (Preferred Resource Strategy Linear Programming Model)
Arizona Public Service	PROMOD IV
Nevada Power / Sierra Pacific Power	PROMOD IV and capital expense software to determine plan costs. Portfolio Pro for evaluating DSM. An econometric model and HELM for load forecasts.
Public Service Company of New Mexico	PROMOD Strategist
Georgia Power Company	Strategist, PROVIEW module. HELM PROSYM to estimate marginal energy cost. REVREK to convert capital costs into revenue requirements. PRICEM (spreadsheet-based) to predict change in revenue requirements attributable to changes in load. EnerSim, EZSimRes, and Site Pro for DSM analysis.
Seattle City Light	AURORAxmp
Northern States Power (Xcel Minnesota)	Strategist
British Columbia Hydro	Multi-Attribute Portfolio Analysis (MAPA) for portfolio evaluation. Hydrological system simulation model (HYSIM). Both are internally developed.

4.16 Use of Proprietary Data

In Table 21 below we note cases where we learned of limitations on publicly available data due to the proprietary nature of the data. It should be noted that “none discussed” does not necessarily mean that all data relevant to the IRP is publicly available; only that

we did not come across any reference to restrictions on public availability of data in our review of the utilities' planning documents.

Table 21. Use of Proprietary Data in Integrated Resource Planning

Utility/Regional Planning Authority	Use of Proprietary Data in Integrated Resource Planning
NWPCC	<p>To the extent possible, data and models are made available for public review and use. This includes the portfolio model developed using Crystal Ball and Excel. For those models not publicly available (GENESYS, AURORA), data sets and results are available for public review. NWPCC encourages and supports the use of its data, models and reports on the part of groups and individuals in the region.</p> <p>The NWPCC does not use utility specific data or proprietary forecasts.</p>
PacifiCorp	None discussed.
Idaho Power	Gas forecasts from IGI resources and PIRA
Puget Sound Energy	None discussed.
Public Service Colorado (Xcel Colorado)	None discussed.
Avista Energy	None discussed.
Arizona Public Service	<p>Resource planning is not yet required in Arizona. APS's publicly available information includes projections of load through the planning period. It does not include fuel information or operating data.</p>
Nevada Power / Sierra Pacific Power	<p>Proprietary data used in preparation of the resource plans and amendments is not made available to the public but can be obtained with a confidentiality agreement. Loads and resource tables, load forecasting information, general information about resources, methodologies for evaluating resource options, results of analysis, etc. are included in the plan. Fuel forecasts, consultants' reports, certain contractual information (operating cost, price), production cost information, financial data, construction cost estimates, etc., are considered proprietary and are excluded from the public filings.</p>
Public Service Company of New Mexico	<p>PNM includes its fuel forecast, demand forecast, and loads and resource table in its publicly available draft IRP. Market price forecasts for purchased power are kept confidential.</p>

Utility/Regional Planning Authority	Use of Proprietary Data in Integrated Resource Planning
Georgia Power Company	GPC's publicly available IRP documents were redacted. GPC files a document with its IRP that lists what it calls trade secret information. This information includes: sensitive details for overall resource planning, such as unit retirement studies, generation analysis and mix data, fuel pricing information, its short-term the load and energy forecast, and its environmental compliance strategy. Long-term loads and resource information in the technical appendix was redacted.
Seattle City Light	None discussed.
Northern States Power (Xcel Minnesota)	None discussed.
British Columbia Hydro	None discussed.
Pacific Gas & Electric	<p>PG&E follows a confidentiality framework established through Rulemaking 05-06-040. Decision 06-06-066 acknowledges the California legislature's preference for open decision-making and public disclosure, but notes that in some circumstances confidentiality protections of market sensitivity information are necessary to avoid the potential for market manipulation.</p> <p>Most market sensitive information, including energy and peak demand forecasts are covered by the confidentiality rules for the front three years.</p>
San Diego Gas & Electric	<p>SDG&E follows a confidentiality framework established through Rulemaking 05-06-040. Decision 06-06-066 acknowledges the California legislature's preference for open decision-making and public disclosure, but notes that in some circumstances confidentiality protections of market sensitivity information are necessary to avoid the potential for market manipulation.</p> <p>Most market sensitive information, including energy and peak demand forecasts are covered by the confidentiality rules for the front three years.</p>

Appendix A: California Statutes Addressing Resource Planning

The following appendix describes the legislation, statutes and policy efforts which either directly impact or relate to the California Public Utilities Commission's ("CPUC") long-term procurement planning process.

A-1 California Policy Initiatives with Bearing on LTPP

A-1.1 ASSEMBLY BILL 57

In 2002, California passed Assembly Bill 57 (AB 57), requiring the CPUC to adopt policies and cost recovery mechanisms for long-term procurement by investor-owned utilities.¹ AB 57 empowers the CPUC to:

- (a) Ensure that the electric corporations create "a diversified procurement portfolio,"²
- (b) Assure "just and reasonable electricity rates;"³
- (c) Provide certainty to the electrical corporations in order to enhance their financial stability and creditworthiness;⁴
- (d) "Eliminate the need, with certain exceptions, for after-the-fact reasonableness reviews of an IOU's prospective electricity procurement performed consistent with an approved procurement plan;"⁵ and

¹ AB 57 (Stats.2002, Ch.850, Sec 3, Effective September 24, 2004), added Public Utilities Code § 454.5

² AB 57 (Stats. 2002, Ch. 850, Sec. 3, effective September 24, 2002), added Pub. Util. Code § 454.5.

³ Pub. Util. Code § 454.5(b)(9)(B)

⁴ Pub. Util. Code § 454.5(c)

⁵ Pub. Util. Code § 454.5(d)(2)

- (e) Assure that each electrical corporation “optimizes the value of its overall supply portfolio for the benefit of its bundled service customers.”⁶

As a result of AB 57, the CPUC established the Long-Term Procurement Plan (“LTPP”) proceeding. In 2001, the CPUC, through its order instituting rulemaking (OIR) R.01-10-024, began the process of re-establishing long-term planning in California. This first procurement proceeding was followed by R.04-04-003, R.06-02-13, and finally the current LTPP (or procurement) docket, R.08-02-007.

A-1.2 ENERGY ACTION PLAN AND INTEGRATED POLICY REPORTS

The California Energy Action Plan I, released in 2003, established the foundation of the state’s ideal for resource procurement with what is called the California “loading order.” This policy sets out the preferred order in which California utilities are to serve their load in the long-term interest of consumers and taxpayers. First, utilities are to reduce electricity demand through energy efficiency and demand response. Second, after all cost-effective demand-side measures are undertaken, utilities are to meet new generation needs with renewable and distributed generation resources. Third, remaining generation needs are to be met with clean fossil-fueled generation. The loading order forms the basis for energy policy and regulatory decisions by state agencies.

In 2005, the Energy Action Plan II updated and revised the first EAP, while maintaining the fundamental findings of the EAP I and further expanding on these goals. In 2008, the Energy Commission and CPUC stated that the California Energy Commission’s Integrated Energy Policy Report (“IEPR”) has largely superseded the need for continued

⁶ D.03-12-062

revisions to the EAP, although the EAP was updated in 2008 to reflect findings of the IEPR and CPUC decisions.⁷

The EAP and the IEPR have both impacted utility resource planning through the LTPP proceedings. Indeed, the OIR of the 2008 LTPP proceeding states that planning will explicitly, “be done in the context of EAPII” with “primary focus in this LTPP proceeding [being] implementation of the EAP loading order” as well as the CEC’s 2007 IEPR procurement-related recommendations (R.08-02-007).

The 2007 IEPR states that the California Energy Commission, “will make the development of a common portfolio analytic methodology a core focus of the *2008 IEPR Update*, with the clear objective of influencing the long-term procurement plans filed by the investor owned utilities with the CPUC in December 2008.” The 2007 IEPR also makes recommendations of relevance to the CPUC LTPP process. These include use of common assumptions in the LTPPs, reflection of ratepayer risk in the LTPPs, extending the period of analysis to a 20 – 30 year timeframe, and incorporating environmental risk and impacts.

The 2008 IEPR Update builds on the recommendations of the 2007 IEPR, also making recommendations specifically directed at the CPUC LTPP process. These recommendations include evaluating ratepayer risk and greenhouse gas uncertainty in resource planning. The 2008 IEPR Update amends one of the recommendations from the 2007 IEPR and recommends avoiding the use of a social discount rate as a means of incorporating natural gas price risk into the resource plans.

A-1.3 RESOURCE ADEQUACY (AB 380)

Assembly Bill 380 (AB 380), passed in 2005, required that the Public Utilities Commission and the Energy Commission work with the California Independent System

⁷ See http://www.energy.ca.gov/energy_action_plan/

Operator (“CAISO”) to oversee utility procurement of resources to meet customer demand.⁸ The bill seeks to ensure that every utility engages in prudent planning to serve customer demand through meeting certain resource adequacy standards. The bill’s specific goals include the requirement to:

“Facilitate the development of new generating capacity and retention of existing generating capacity that is needed and economic; Equitably allocate the cost of generating capacity and prevent shifting of costs between customer classes; and Minimize enforcement requirements and costs.”⁹

Resource adequacy (“RA”) is currently being addressed at the CPUC through two open proceeding R.08-01-025 and R.05-12-013. The former proceeding will establish local procurement obligations for 2009 based on a study of Local Capacity Requirements (“LCR”) performed by the CAISO. It may also consider the “(1) review of the rules for counting the net qualifying capacity (NQC) of intermittent resources, (2) review of outage counting rules to ensure coordination of the RA program with CAISO tariff provisions, (3) monthly true-ups of local procurement obligations for load migration impacts, (4) review of the counting rules for new resources, (5) review of whether and how QF [Qualifying Facility] resources whose contracts are extended pursuant to Decision (D.) 07-09-040 count for RA compliance, and (6) modification of the RA compliance filing procedure to reduce paperwork and the need for corrections.” The findings of this resource adequacy proceeding will inform the LTPP proceeding.

Perhaps of longer-term relevance for the LTPP is the consideration of proposals for “second-generation” resource adequacy issues such as local resource adequacy requirement (“RAR”), multi-year RAR, capacity tagging, and forward capacity markets through Track 2 of Phase 2 of R.05-12-013. If the Commission decides that the state

⁸ AB 380 (Stats. 2005, Chapter 367), added Public Utilities Code § 380.

⁹ Assembly Bill 380, 2005.

should move ahead with the development of forward capacity markets, the need for capacity planning for system reliability in the LTPP could eventually be eliminated.

A-1.4 RENEWABLE PORTFOLIO STANDARD (SB 107)

In 2002, Senate Bill 1078 (SB 1078) established the California Renewable Portfolio Standard (“RPS”). SB 1078 required electrical retail sellers, excluding local publicly-owned utilities, to obtain 20 percent of their retail sales from renewable sources no later than the year 2017, and defined the criteria for RPS eligibility. In 2006, Senate Bill 107 (SB107) accelerated the schedule for RPS compliance to 20 percent by the year 2010, and required publicly-owned and investor-owned utilities to develop RPS compliance plans.

Senate Bill (SB) 1036 (Statutes of 2007), effective January 1, 2008, modifies elements of the RPS program related to the funding mechanism for renewable energy development. Specifically, SB 1036 directs the CPUC to establish, for each IOU, a limitation on the total costs expended above the market price referent (MPR) for the procurement of eligible renewable energy resources to satisfy RPS goals. Effectively, this means that renewable generators and IOUs must now seek approval from the CPUC for above-market cost recovery for RPS contracts.

The State’s 2005 Energy Action Plan II (“EAP II”) set out a further goal of 33 percent RPS by 2020, which has been supported by the Governor and the California Air Resources Board Proposed Scoping Plan, which lays out the state’s proposed implementation approach to reach required greenhouse gas emission limits by 2020. It remains uncertain whether the 33 percent RPS goal will become law, although currently such proposals are under consideration in the 2009 legislative sessions of the State Senate and Assembly.¹⁰ In addition, the fact that the Governor supported a 33 percent RPS in *Executive Order S-14-08*, and the fact that all of the state’s energy regulatory agencies

¹⁰ For example, proposed Assembly Bill 64 (Krekorian) and proposed Senate Bill 805 (Wright).

support the 33 percent RPS by 2020 proposal, suggests that the proposal has significant momentum.

The CPUC is currently using two rulemakings to implement that state's RPS requirements. Through Rulemaking 08-08-009, the CPUC oversees implementation and administration of the RPS law through the filing of yearly RPS Procurement Plans and transmission ranking cost reports. In contrast, RPS Rulemaking 06-02-012 focuses more on coordinating RPS policy with other CPUC policies such as the California Solar Initiative ("CSI"), and other policy implementation questions, such as the characterization of Renewable Energy Credits ("REC") and to what extent electric service providers, community choice aggregators, small utilities, and multi-jurisdictional utilities will participate in the RPS program.

These RPS decisions will flow into the LTPP docket, informing the assumptions about renewable energy procurement that the IOUs should make in their analyses. Likewise, through the LTPP, CPUC staff have undertaken an analysis of the 33 percent RPS implementation barriers, project timelines required to meet the RPS goal and proposed solutions to streamline renewable development in the state.

A-1.5 EMISSIONS PERFORMANCE STANDARDS (SB 1368)

Senate Bill 1368 (SB 1368), passed in 2006, establishes *Emissions Performance Standards* for greenhouse gas emissions of power plants used to serve load in California. Under SB 1368, utilities may only sign long-term contracts of five years or more with power plants that produce no more greenhouse gas emissions than an emissions performance standard jointly established by the CPUC and the CEC. This threshold level was set at 1,100 pounds of CO₂ per MWh of electricity generated by the plant (or approximately the emissions intensity of an older natural gas-fired unit). This law effectively prohibits California utilities from owning or entering into long-term contracts with coal-fired power plants, in- or out-of-state, unless the unit operates with carbon capture and

storage. Implementation of SB 1368 takes place through the same CPUC docket (R.06-04-009) as the greenhouse gas legislation implementation.

A-1.6 THE GLOBAL WARMING SOLUTIONS ACT (AB 32)

In 2005, California's Governor Schwarzenegger laid out statewide goals for responding to climate change in *Executive Order S.03-05*. This order called for California to reduce its greenhouse gas emissions to 1990 levels by 2020, with a stretch goal of reducing emissions 80 percent below 1990 levels by 2050. The 2020 target became law in 2006 as Assembly Bill 32 (AB 32). AB32 requires the California Air Resources Board ("CARB") to develop regulatory and market methods to ensure statewide compliance with the greenhouse gas targets, which will begin to take effect in 2012. The CPUC and CEC (through R.06-04-009 and docket 07-OIIP-01) have developed specific proposals to CARB for implementing AB32 in the electricity sector, including increased energy efficiency goals, implementation of a multi-sector cap and trade program and support for implementation of a 33 percent RPS.

In the Commission's Order Instituting Rulemaking of the 2008 LTPP proceeding, the Commission stated that one of the "guiding principles" of the LTPP is to anticipate AB 32 constraints on IOU electricity portfolios.¹¹ The 2010 LTPPs are thus likely to consider the AB 32 recommendations of CARB's Proposed Scoping Plan and of the CPUC/CEC's greenhouse gas docket in developing appropriate scenarios for analysis.

A-1.7 MILLION SOLAR ROOFS INITIATIVE (SB 1)

Beginning in 2004, the California Governor announced the "Million Solar Roofs" Initiative which set the target of installing 3,000 MW of new solar photovoltaic capacity statewide by 2017. In 2006, the California Legislature approved Senate Bill 1 (SB 1),

¹¹

which adopted this goal into law, and directed the CPUC and the CEC to implement the solar initiative consistent with certain budgetary requirements and statutes.

To help achieve this goal, the CPUC has adopted the California Solar Initiative (“CSI”), which works with the three large California IOUs to provide incentives for solar PV installations in order to reach the goals of 1,940 MW of new installed solar PV by 2016. The New Homes Solar Partnership, managed by the CEC, is working with new home construction located within the IOUs’ service territories to install 360 MW of new solar PV. In addition, Publicly Owned Utilities (“POUs”) are required under SB 1 to offer solar incentive programs, with the goal that POU solar programs will achieve 700 MW of new solar installations by 2017.

The CPUC’s current proceeding for CSI program rules is occurring under R.08-03-008. This proceeding is developing policies that encourage clean, distributed generation in California through appropriate incentives and rate design structures. The proceeding specifically is developing policies and programs to support the CSI, considering policy issues surrounding distributed generation and management of the Self-Generation Incentive Program (“SGIP”), and resolving some of the cost-benefit methodologies explored in the previous distributed generation Rulemaking 06-03-004.

The LTPPs will need to make some assumptions about the future of rooftop solar PV. There are two key implications of the CSI program for the LTPPs, the first being changes to the load forecast. The CEC’s load forecast for the 2007 IEPR assumed that current solar PV installation rates continue into the future, meaning that the statewide goal of 3,000 MW is not projected to be met in the forecast. If the LTPP undertakes scenarios representing higher or lower levels of rooftop PV installations than is assumed in the CEC’s load forecast, demand levels will need to be adjusted accordingly. The LTPPs will also need to track the cost associated with the payment of utility incentives for the CSI program. If it is determined in the LTPP docket that customer costs should be

reported as well, the customer-paid portion of rooftop solar installations will also need to be tracked.

A-1.8 CALIFORNIA NUCLEAR ENERGY LEGISLATION

California state law prohibits the construction of new nuclear power in-state until the CEC finds that the federal government has approved, and there exists, a demonstrated technology for the permanent disposal of spent fuel from nuclear facilities.¹² This law, passed in 1976, has effectively blocked all new nuclear development in the state. A 2006 status report on nuclear power in California, prepared for the CEC, concluded that the nuclear storage issue was not likely to be resolved in the near future. This de-facto ban on nuclear power in the state means that California will need to work harder to find new sources of low-carbon energy. The law also means that it is not likely that nuclear power will be a procurement option for IOUs in their LTPPs.

A-1.9 REPOWERING OF EXISTING FACILITIES (SB 1576)

Assembly Bill 1576 (AB1576), passed by the Legislature in 2005, seeks to streamline the repowering of aging but strategically important power plants, or power plants that are “interconnected to gas transmission pipelines and the electric transmission system in a manner that optimizes their reliability, deliverability, their cost effectiveness, and their ability to deliver power to load centers.” The law allows the CPUC to approve contracts between IOUs and these strategically important power plants on a long-term cost of service basis. Under the law, IOUs are allowed to recover the full cost of the contract through customer rates.

Through the previous LTPP proceeding (R.06-02-013), the CPUC held working groups to discuss the interpretation of the statutory criteria for repowering and replacement of generating facilities that are eligible for AB 1576 status, as set forth in Public Utilities Code section 454.6(b). The final decision in this docket concluded that:

¹² See California Public Resources Code Sections 25524.1 & 25524.2.

“Encouraging the retirement or repowering of these older units also supports a variety of California’s policy aims (e.g., reduction of once-through cooling units, Brownfield development per the goals set out in AB 1576, air quality goals, and reduction of GHGs). Consequently, our goal is to strike a balance between inducing retirements or repowerings through our procurement authorizations and containing the costs associated with replacing many of these facilities in a short period of time.”¹³

Likewise, the decision noted that, “Preference should be given to procurement that will encourage the retirement of aging plants, particularly inefficient facilities with once-through cooling, by providing, at minimum, qualitative preference to bids involving repowering of these units or bids for new facilities at locations in or near the load pockets in which these units are located.”¹⁴ This direction, provided by the Commission, will guide the current LTPP docket as the next rounds of procurement decisions are made.

In addition, as will be discussed below, the State Water Board is in the process of developing new environmental rules that may restrict the use of once-through cooling in power plants. Restrictions on the use of once-through cooling could have important implications for long-term resource planning if critical generators, used for resource adequacy or reliability needs, are re-powered or retired as a result of the regulations.

A-1.10 ENERGY EFFICIENCY GOALS (AB 2021)

Assembly Bill 2021 (Statutes of 2006) requires the CEC to develop statewide estimates of all potentially achievable cost-effective energy efficiency savings for electricity and natural gas, and to adopt statewide targets for energy efficiency savings over a ten-year

¹³ D.07-12-052, p. 89

¹⁴ D.07-12-052, p. 106

period. The CEC adopted the statewide target of achieving 100 percent of economic potential, as defined by the 2006 Itron Energy Efficiency Potential Study in the 2007 IEPR.

In the current CPUC energy efficiency proceeding (R.06-04-010), these statewide targets were considered in the development of specific energy efficiency targets for the three large IOUs. Decision 08-07-047 defines energy efficiency savings targets for 2009 – 2011, and adopts interim energy efficiency targets for 2012 – 2020. The energy efficiency targets for 2009 – 2011 represent a break from previous policy in that they shift the efficiency goals from net to gross goals, meaning that the CPUC will not perform an adjustment of energy efficiency savings attributable to IOU programs due to the ‘free-rider’ effect. The 2012 – 2020 interim goals also reflect this trend away from estimating the free-rider effect of energy efficiency savings, and instead set “Total Market Gross” (“TMG”) savings goals for the IOUs. The decision, in ordering paragraph 3, concludes that 100 percent of the interim TMG goals for 2012 – 2020 shall be used in all LTPP filings, until superseded by permanent goals.

A-2 Other CPUC Proceedings with Bearing on LTPP

The following is a list of additional CPUC proceedings, not discussed above, which have bearing on the LTPP. Additional procurement related Rulemakings may be opened by the CPUC, which would have bearing on the Long Term Procurement Plan proceeding in R.08-02-007.

A-2.1 DEMAND RESPONSE AND ADVANCED METERING, A.07-12-009, A.05-06-006 ET AL., R.07-01-041

California first articulated its target for aggressive demand response peak capacity savings in the Energy Action Plan in 2003. That year, the CPUC defined a demand response target for the three IOUs, setting the goal at a 5 percent reduction in peak demand by 2007 (D.03-06-032). These targets were not fully achieved by 2007, leading the CPUC to work towards developing better, more effective demand response

programs, partly through IOU deployment of advanced metering (“AMI”) technologies. For example, in A.07-12-009 the Commission approved PG&E’s application to its SmartMeter Program Upgrade.

Additionally, the CPUC opened proceeding R.07-01-041 to develop measurement and evaluation protocols for estimating the impact of demand response activities on electric load. Through the same proceeding, the CPUC is also seeking to develop appropriate demand response programs which will be able to participate in the day-ahead electricity market being developed by the CAISO. A.05-06-006 dealt with evaluating the cost-effectiveness of the IOU’s demand response programs. Currently, the Commission is considering what appropriate demand response programs and funding levels should be for the three IOUs through the 2009 – 2011 programmatic period. This effort is taking place under a combined proceeding of A.08-06-001, A.08-06-002 and A.08-06-003. These proceedings will inform the LTPP’s treatment of demand response in procurement plans.

A-2.2 DYNAMIC PRICING, A.06-03-005

The CPUC seeks to make dynamic pricing available to all customers. This proceeding adopted a dynamic pricing timetable for Pacific Gas and Electric (PG&E), and provided rate design guidance for PG&E. The purpose of dynamic pricing includes aligning wholesale price fluctuations with retail prices, in part to provide customers an incentive to reduce electrical demand during peak hours and to encourage more economically efficient choices.

A-2.3 AVOIDED COST AND QUALIFYING FACILITY PRICING, R.04-04-025

The Rulemaking R.04-04-025 adopts an avoided cost methodology, to calculate the total avoided cost of power that a utility would have to procure in the absence of demand-side resources, such as energy efficiency. The methodology is used in cost-effectiveness tests to evaluate energy efficiency programs. The Rulemaking also develops policies and pricing mechanisms applicable to IOUs’ purchase of energy and capacity from

Qualifying Facilities (“QFs”) pursuant to the Public Utilities Regulatory Policy Act of 1978 (“PURPA”), which is also based on an avoided cost methodology.

A-2.4 TRANSMISSION AND RENEWABLE ENERGY TRANSMISSION, I.08-03-010 AND R.08-03-009

The Investigation 05-09-005, now closed, identified ways to streamline and improve the CPUC’s transmission planning and permitting processes as they relate to renewable energy development. It adopted a backstop cost recovery mechanism for renewable energy transmission construction. In addition, to the extent possible, the Investigation sought to streamline transmission permitting. This effort resulted in the issuance of the CPUC “Executive Director’s Statement Establishing Transmission Project Review Streamlining Directives” in July 2006. As a result of the Investigation, the Commission began tracking all RPS projects under contract, and seeks to identify when the projects may be at risk due to lack of transmission. While the Investigation identified and addressed some of the “easy-fixes” for renewable energy transmission development, the Commission acknowledged in the Opinion Closing the Docket that, “our work is not done... given the role of renewables in meeting the State’s recently enacted Global Warming Solutions Act, we must continue to be proactive in the development of additional transmission projects necessary to reach remotely located renewable resources.”¹⁵ A new renewable transmission joint Investigation/Rulemaking was opened in March 2008 to further streamline regulatory processes to improve transmission access to renewable generation, and to address any issues in RETI that might require Commission investigation or decisions.

A-2.5 CONFIDENTIALITY, R.05-06-040

This Rulemaking implements Senate Bill 1488 (statutes 2004) as it applies to electric procurement. The Bill requires the CPUC to examine whether the CPUC’s policies

¹⁵ CPUC Opinion Closing the Docket, I.05-09-005, pg. 2.

regarding confidential information sufficiently ensure public participation and open decision-making in the proceedings.

A-2.6 PLANNING RESERVE MARGIN, R.08-04-012

The Planning Reserve Margin (“PRM”) proceeding reviews and may decide to modify the current PRM, which requires that utilities maintain and procure a certain level of resources to meet their peak demand plus an appropriate operating reserve margin. The outcome of the PRM will feed into the RA and LTPP proceedings.

A-2.7 LIQUEFIED NATURAL GAS, R.07-11-001

This proceeding addressed the question of whether investor owned utilities should enter into specific, long-term procurement contracts with liquefied natural gas (“LNG”) suppliers on the West Coast. The purpose of the proceeding was to help ensure a sufficient supply of reasonably-priced natural gas in California. D.08-10-025 concluded that, in general, LNG should compete head to head with domestic natural gas supplies, and procurement and cost recovery rules should be the same as apply to domestic natural gas supply.

A-2.8 DIRECT ACCESS, R.07-05-025 AND ITS SUCCESSOR

Currently, the ability of new customers to purchase electricity on a direct access basis is suspended, following the electricity crisis of 2000 and 2001. The Direct Access Rulemaking is investigating whether and how the direct access market should be reopened. Decision 08-02-033 of this docket concluded that the CPUC does not have the authority at this time to reverse the suspension on Direct Access. The Commission also stated that it “remains committed to exploring pro-active alternatives whereby the legal conditions allowing for the lifting of the suspension could be satisfied,” Noting that, “we make no prejudgment in this decision concerning the substantive merits of how any reinstituted direct access market should function consistent with the public interest” (D.08-02-033, pg. 2). Decision 08-11-056 adopted a plan to remove the Department of

Water Resources from supplying electric power to customers which would pave the way for a re-opening of direct access, potentially by 2010.

A-2.9 COMMUNITY CHOICE AGGREGATION, R.03-10-003 AND ITS SUCCESSOR

The proceeding considers issues related to the implementation of Assembly Bill 117 that permits local governments to purchase energy on behalf of local customers in the form of a Community Choice Aggregator (“CCA”). The proceeding also considers the distribution of certain utility costs to CCAs, as well as transactions between CCAs, customers, and electric utilities.

A-2.10 RENEWABLE ENERGY TRANSMISSION INITIATIVE (RETI)

The Renewable Energy Transmission Initiative (“RETI”) is a joint effort of the CPUC, the CEC, the CAISO and publicly-owned utilities (Southern California Public Power Authority, Northern California Power Agency, and the Sacramento Municipal Utility District) to identify transmission needs and to facilitate transmission corridor planning and siting needs to meet the state’s renewable portfolio standard goals. RETI is assessing competitive renewable energy zones (“CREZs”) in California and neighboring states which will be able to provide energy to California by 2020. The data from the RETI process was utilized in the CPUC staff 33 percent RPS implementation analysis, and may be utilized in the 2010 LTPPs to the extent that it is feasible and useful to do so.

A-3 Environmental Permitting Regulations in California

This section describes some of the environmental permitting requirements in California which affect utility procurement and planning around generation and transmission resources. This section also highlights some of the challenges associated with new generation and transmission development, and hence the need to anticipate realistic timelines required to bring new infrastructure and generation projects on-line.

A-3.1 CLEAN WATER ACT AND ONCE-THROUGH COOLING

The California Water Board is currently considering a statewide policy to reduce the environmental harm caused by once-through cooling (“OTC”). Currently twenty-one of the state’s nuclear and thermal generating units use one-through cooling and may be affected by the Water Board proposed regulation. The Water Board would enact the regulation in response to the Clean Water Act section 316(b) which requires that, “the location, design, construction, and capacity of cooling water intake structures reflect the best technology available (“BTA”) for minimizing adverse environmental impact.”

The proposed regulations could result in the re-powering or shut-down of up to 20 percent of the state’s energy generation. Although a number of the state’s generating units using OTC do not produce power during many hours of the year, these units remain important for system reliability and resource adequacy.¹⁶ The Water Board is seeking to develop a regulation which addresses the state’s environmental concerns but which also maintains needed generation capacity to ensure reliability.

Currently, the Water Board expects to release a Draft Policy for the treatment of once through cooling at coastal and estuarine power plants in summer 2009.¹⁷ This will initiate a public workshop, public hearing and comments period, after which the final regulation will be developed. The draft policy will replace the “Proposed Statewide Policy on Clean Water Act Section 316(b)” released in March 2008.¹⁸ The proposed

¹⁶ Jones & Stokes. 2008. Electric Grid Reliability Impacts from Once-Through Cooling in California. April. (J&S 041808) Sacramento, CA. Available at: http://www.waterboards.ca.gov/water_issues/programs/tmdl/docs/power_plant_cooling/reliability_study.pdf

¹⁷ See http://www.swrcb.ca.gov/water_issues/programs/npdes/cwa316.shtml

¹⁸ State Water Resources Control Board, California Environmental Protection Agency, 2008. “Scoping Document: Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling,” March. Available at: http://www.swrcb.ca.gov/plans_policies/docs/coastal_estuarine/scope_doc031808.pdf

policy may not be finalized in time to incorporate into the LTPP filings; however, some assumptions about how the proposed OTC regulation will affect the power plants' operations, and thus the IOUs procurement decisions, may be needed to ensure that the LTPPs reflect the best-available information about the future landscape of procurement needs in California.

A-3.2 CALIFORNIA ENVIRONMENTAL QUALITY ACT

New generating units and major transmission projects must comply with the California Environmental Quality Act ("CEQA") which requires a thorough analysis of environmental issues and potential impacts. Thermal plants (gas-fired, solar thermal, geothermal) over 50 MW must be certified by the CEC, which conducts a CEQA-equivalent analysis. For thermal plants less than 50 MW and for wind and solar photovoltaic ("PV") (and non-thermal solar plants), permitting and CEQA compliance falls to local jurisdictions. Generation facilities on federal land also require compliance with the National Environmental Policy Act ("NEPA"), typically through preparation of an Environmental Impact Statement ("EIS").

CPUC General Order ("GO") 131-D governs application and environmental review requirements for transmission lines. Major transmission lines can require several years for routing studies as well as participation in stakeholder processes for path selections and ratings. After submittal of a complete application for Certificate of Public Convenience and Necessity ("CPCN"), the CPUC manages the preparation of an Environmental Impact Report ("EIR") or a joint EIR/EIS if federal land is also involved.

CEQA and NEPA compliance can require significant upfront analyses and permitting timeframes that can be lengthened when multiple agencies are involved (particularly if agency backlogs exist), or when complex issues arise or there is considerable public involvement. The CEQA and NEPA processes require comprehensive consideration of alternatives to projects. Alternatives to generation facilities or major transmission projects are subject to analysis under the CEQA Guidelines if the alternatives are capable

of reducing significant adverse environmental effects of a project, even if the alternatives are more costly or impede to some degree the attainment of the project objectives.

CEQA (and potentially NEPA) compliance will be ultimately required for all facilities considered in LTPPs.

A-3.3 CEQA GUIDELINES AND GREENHOUSE GASES

Pursuant to Senate Bill 97 (Chapter 185, 2007), the Governor's Office of Planning and Research ("OPR") must develop guidelines on the analysis and mitigation of GHG emissions in CEQA documents. OPR is required to "prepare, develop and transmit" the guidelines to the Resources Agency by July, 2009, whereupon they must be certified and adopted by January 2010. In conjunction with the Resources Agency, the California Environmental Protection Agency and CARB, OPR issued informal guidance in June 2008 regarding the steps lead agencies should take to address climate change in their CEQA documents. All facilities considered in LTPPs will now be required to address GHGs at the time of environmental permitting. Proposed transmission lines will also be required to address GHGs.

A-3.4 PRIORITY RESERVE CREDITS

A court decision in late July 2008 ruled that the South Coast Air Quality Management District ("SCAQMD") could not sell credits to offset air pollution from proposed new power plants without a more extensive analysis under CEQA. Environmental advocates asserted that the SCAQMD had been selling credits from its Priority Reserve Fund to energy companies at below market value. The court ruling could affect 11 proposed plants in the Los Angeles Basin, and two in Desert Hot Springs and Victorville; additional fossil-fueled plants could be affected in the future. LTPP filings may need to consider the feasibility of obtaining sufficient offsets for particulate matter and ozone or smog precursors, which are very limited in the open market, to allow permitting natural gas-fired plants in the SCAQMD region.

A-4 California Independent System Operator Processes with Implications for LTPP

This section describes some of the processes which occur through the California Independent System Operator (“CAISO”) influencing generation and transmission development.

A-4.1 MARKET REDESIGN AND TECHNOLOGY UPGRADE (MRTU)

In April 2009 the CAISO began a new day-ahead market and an integrated forward market as part of its Market Redesign and Technology Upgrade (“MRTU”), which launched in March 2009. The new markets distinguish between energy, congestion management and ancillary services. The day ahead market includes a pricing system that identifies Locational Marginal Pricing (“LMP”) based on the actual cost of delivering power to congested areas and new market rules and penalties to help the CAISO maintain grid reliability. MRTU also updated the CAISO’s computer system, allowing the CAISO to more accurately model the grid in operation, to predict how energy scheduled one day ahead will flow over the grid in real time, and to avoid computer downtime and interruptions.

It is not entirely clear yet how MTRU will affect utility long-term planning or resource procurement, although the LMP component of the new market may make certain resources, located in load pockets or other transmission constrained areas, more economically attractive. Likewise, the MRTU is expected to include an increased ability for demand response to participate as a resource in a market, which may increase the deployment of demand response in the state, thus contributing to a reduction in peak load demand. The CPUC open proceeding R.07-01-041 is currently addressing the issue of how to ensure that IOU demand response programs are adaptable to functioning in the CAISO day-ahead markets, as implemented under MRTU.

In addition, the 2008 LTPP scoping memo requests comments from stakeholders, “as to whether and where state laws or the Commission’s decisions would require

modifications to its procurement programs or further modifications to IOU procurement plans because of the implementation of new market features and energy-related products.”¹⁹ The Commission is particularly interested in considering how Congestion Revenue Rights (“CRR”) and the proposed Virtual Bidding (“VB”) market may affect procurement.

A-4.2 CALIFORNIA ISO TRANSMISSION PLANNING PROCESS

Transmission planning in California is a complex process involving multiple state agencies as well as the Federal Energy Regulatory Commission (“FERC”). In order to promote competition in wholesale bulk-power electricity markets, FERC requires utilities and ISOs to implement an “Open Access Transmission Tariff” (OATT). OATT reform requires the CAISO to provide transmission services that are just, reasonable and not unduly discriminatory to new market entrants. Partly to comply with FERC’s OATT, the CAISO maintains an interconnection queue of proposed generation projects, so that each project may be evaluated based on the transmission requirements needed to connect the proposed generator to the grid. Currently, the CAISO interconnection queue contains approximately 13,000 MW of solar and wind projects, and the Imperial Irrigation District, LADWP, and SMUD queues contain additional MWs of renewable projects.²⁰ Utilities may also propose transmission upgrades, so as to maintain grid reliability, which are evaluated by the CAISO separately from projects in the interconnection queue.

In addition, in compliance with FERC Order No. 890, the CAISO produces a long-term transmission plan for California in an effort to bring together industry information on projected load growth, proposed generation projects, re-powering and retiring and

¹⁹ Assigned Commissioner’s Ruling and Scoping Memo on the 2008 Long-Term Procurement Proceeding, Phase 1, R.08-02-007, pg. 19.

²⁰ CAISO Interconnection Queue, as of March 6, 2009.

planned transmission projects.²¹ The ISO transmission plan analyzes the economic and grid reliability impacts of transmission congestion and estimates needed local generation and infrastructure improvements. This means that transmission planning requires coordination between utilities, independent energy producers, and the CAISO, as well as the CEC and CPUC which are responsible for permitting transmission projects.

Many efforts are underway to streamline and improve the state's transmission planning process, including through the RETI, discussed above. However, regardless of the outcome of these efforts, it seems clear that coordination between utility long-term planning in the LTPP and CAISO long-term transmission planning will be necessary.

²¹ See for example, the 2008 CAISO Transmission Plan available at:
<http://www.caiso.com/1f52/1f52d6d93a3e0.pdf>

Appendix B: Individual Utility and Planning Area Summaries

B-1 Northwest Power and Conservation Council (NWPCC)

B-1.1 LOAD FORECASTING

The NWPCC's Fourth Power Plan used a detailed Demand Forecasting System ("DFS") which built aggregate forecasts from detailed economic forecasts of end-use by sector. The NWPCC chose not to re-run the DFS for the Fifth Power Plan (September 2004) because it was found to be too expensive and time consuming and because much of the data required was not available at the level of accuracy or detail needed to support the analysis.

The NWPCC used three separate approaches in extending the previous DFS forecast forward:

1. A near-term monthly forecast of the non-direct service industry ("DSI") demand recovery from the energy crisis in 2000-2001 was developed for the medium case only. This focused on the regional recovery from the high energy prices and economic recession in the beginning of the decade.
2. Low, medium and high long-term scenarios for non-DSI loads were developed for 2005-2025. This method extends the Fourth Power Plan forecast using relatively simple approaches to expand geographic and temporal dimensions of forecast. The key determinates for the extended approach are population, number of households and non-farm employment. Forecasts are developed for the residential, commercial and industrial sectors.
3. Direct service industries ("DSI") are a group of industrial plants, dominated by aluminum smelters, that purchase electricity directly from BPA. A separate "simple" model was developed for DSI using aluminum and electricity prices as key determinants of demand.

For non-DSI demand a Load Shape Forecasting System module builds hourly shapes based on end-use equipment. A portfolio model (described below) introduces random variation in hourly load shapes. The “HELM algorithm” is used to assess demand variations as a function of temperature.

The AURORA electricity model is used for estimates of demand growth in other western areas. The NWPCC also uses California Energy Commission (“CEC”) and National Energy Board forecasts.

B-1.2 NEEDS DETERMINATION

The NWPCC performs two analyses. The first analysis uses the GENESYS model, a probabilistic model that performs a detailed simulation of the Northwest power system. The model assesses the ability of the system to meet load with variations in hydro conditions, temperatures and generator outages. The second analysis uses a portfolio model to explore the cost/risk tradeoff over a large number of possible futures.

The random (or uncertain) variables modeled in GENESYS are Pacific Northwest stream flows, Pacific Northwest demand and generating-unit forced outages. The demand algorithm in GENESYS uses daily average temperatures to forecast hourly demands. In order to maintain the correlation between temperature and precipitation (river flows), the model is normally run with these two variables in lockstep.

GENESYS does not model long-term demand uncertainty (other than temperature variations) nor does it incorporate any mechanism to add new resources should demands grow more rapidly than expected. It performs its calculations for a known system configuration and a known demand forecast, which can change over time. In order to assess the physical adequacy of the system over different long-term demand scenarios, the model must be rerun using the new demands and the corresponding new resource additions.

To assess risks and impacts for hydroelectric operations, three sets of hydrological data were produced for operating years 2020 and 2040. Each is a downscaled and bias-adjusted set of water conditions generated using output from a particular global model. The first two sets of water conditions are derived from the HC and MPI models and the third set is derived from a combination of model runs (“COMP”). The study was deterministic; each projection was given an equal likelihood of occurring and only the current generating mix was modeled in GENESYS.

Records required curtailments to calculate loss of load probability (“LOLP”). The modeling assumes all resources will be dispatched in economic order regardless of cost. Adequate LOLP is defined to be no greater than 5 percent over the winter period.

B-1.3 TIME PERIOD OF ANALYSIS

20 years, 2005-2025.

With restructuring, and focus on shorter lead time projects (e.g. CT vs. Nuclear), the focus is now on five-year forecasts and near-term reliability and resource adequacy.

B-1.4 FUEL AND ELECTRICITY MARKET PRICE FORECASTING

The NWPCC uses an Excel model of commodity price trends based on past experience, market behavior and other organization’s forecasts. The model adds transportation and distribution costs to calculate prices at various points in the Pacific Northwest. The model is not a supply/demand model. Natural gas receives a greater focus than oil or coal given its importance in determining marginal electric prices.

The natural gas price forecasts begin with a forecast of average U.S. wellhead prices. These are used to estimate prices at other trading points throughout the West. Where supported by historical data, regression equations were estimated that relate these various natural gas prices.

For the purpose of electricity price forecasting, the NWPCC uses the weighted average of the expected mix of project owners for each resource type. For example, trends suggest that most wind projects will continue to be developed by independent power producers. Thus the “expected mix” for future wind capacity is 15 percent consumer-owned utility, 15 percent investor-owned utility and 70 percent independent power producer. For comparative evaluation of resources, including the portfolio analysis and the benchmark prices appearing in the plan, the Council uses a “standard” ownership mix. This consists of 20 percent consumer-owned utility, 40 percent investor-owned utility and 40 percent independent power producer ownership.

B-1.5 RESOURCE COST DEVELOPMENT METHODOLOGY

NWPCC Staff develops and publishes its own cost of generation estimates. The estimates include detailed plant specifications and financing assumptions for each technology. The report relies upon a number of sources and surveys including Electric Power Research Institute (“EPRI”), U. S. Department of Energy (“USDOE”), National Energy Technology Laboratory (“NETL”) and others.

The report contains descriptions of the available technology and expected future technological development, plant economics, development issues and regional potential. The NWPCC then describes a detailed reference plant that is used in the portfolio and risk models.

B-1.6 TREATMENT OF ENERGY EFFICIENCY

The NWPCC’s portfolio model is designed to compare resources, including conservation, on a “generic” level. In the case of conservation, the model uses two separate supply curves. These supply curves, one for discretionary resources and a second for lost opportunity resources, depict the amount of savings achievable at varying costs.

The Northwest Power Act directs the NWPCC and Bonneville Power Administration (“BPA”) to give conservation a 10 percent cost advantage over sources of electric generation. The NWPCC does this by adding 10 percent to its avoided cost estimate (including both the forecast of wholesale market power prices and transmission and distribution cost deferral) when calculating benefit-to-cost ratios.

B-1.7 MARKET PRICE RISK ASSESSMENT

NWPCC creates a base case electricity price forecast using the medium load forecast, medium fuel price forecast, average hydropower conditions, mean GHG mitigation costs and new resource cost and performance characteristics. The NWPCC uses the AURORAxmp electricity market model. The model bases electricity prices on the variable cost of the most expensive generation plant or load curtailment needed to meet forecasted load in each hour.

NWPCC contracted BHM3 Consultants to perform detailed statistical analysis using Crystal Ball/Excel based Monte Carlo Simulation. The uncertainties include:

- **Load requirements:** The NWPCC’s load forecast range for non-aluminum loads serves as a basis for the characterization of uncertain load trends. The expected load and the long-term load probability distribution are consistent with the forecast range. However, additional variations in load are added in the portfolio analysis to reflect seasonal and hourly patterns of load as well as excursions for weather variations and business cycles.
- **Fuel prices:** The basis for uncertain natural gas price trends is the NWPCC’s fuel price forecast range including estimates of uncertainty in the expected annual price. In addition to uncertainty in long-term trends in fuel prices, the modeling representation uses seasonal patterns and brief excursions from trends. These excursions may last from six months to four years and then recover back toward the trend path. The duration of the excursion and the duration of the price recovery are both functions of the size of the excursion.

- **Hydrogeneration:** A 50-year history of streamflows and generation provide the basis for hydro generation in the model. The hydro generation reflects constraints associated with the NOAA Fisheries 2000 biological opinion. The modeling assumes a decline of 300 average megawatts over the 20-year study period to capture relicensing losses, additional water withdrawals, the retirement of inefficient hydro generation units, and other factors that might lead to capability reduction.
- **Electricity price:** Disequilibrium results from less than perfect foresight about supply and demand, inactivity due to prior surplus, overreaction to prior shortages, and other factors. Periods of disequilibrium can last as long as it takes for new capacity to be constructed or released, or surplus capacity to be retired or “grown into.” NWPCC contracted BHM3 Consultants to perform detailed statistical analysis on the relationships between hydro-generation, loads, temperature, natural gas prices, electric power prices, and transmission. The System Analysis Advisory Committee reviewed the results of these analyses. These analyses form the basis for the NWPCC’s representations of price paths, uncertainties, volatilities, and correlations.
- **Forced outage rates:** Power plants are not perfectly reliable, and forced outages are an important source of uncertainty. The analysis includes simulation of forced outages based on typical forced outage rates for the generating technologies considered.
- **Aluminum price:** The portfolio model captures the relationship among varying aluminum prices, electricity prices, and aluminum plant operation. In addition, the analysis considers the likelihood of permanent aluminum plant closure if a plant is out of operation for an extended period. Given the future electricity and aluminum price trends and variations and absent some policy intervention, the

portfolio model results show an 80 percent likelihood of all aluminum plants closing during the forecast period.

- **CO2 tax:** In the model, a carbon tax can arise in any election year. The probability of such a tax being enacted at some time during the forecast period is sixty-seven percent. If enacted, the value for the carbon tax is selected from a uniform distribution between zero and \$15 per ton if it is enacted between 2008 and 2016, and between zero and \$30 per ton if enacted thereafter (2004\$).
- **Production tax credits:** There is a small probability the production tax credit (“PTC”) could disappear immediately, if Congress decided renewable energy technology is sufficiently competitive and funds are needed elsewhere. The likelihood of termination peaks in the model when the fully allocated cost of wind approaches that of a combined cycle power plant around 2016. The second event that modifies the PTC in the NWPCC’s model is the advent of a carbon penalty. This event is related to the first, in that a carbon penalty would make renewables that do not emit carbon more competitive relative to those generation technologies that do. For this reason, the value of the PTC subsequent to the introduction of a carbon penalty depends on the magnitude of the carbon penalty.
- **Green tag value:** In the model, green tag value can start the study period anywhere between \$3 and \$4 per megawatt-hour with equal likelihood (2004\$). By the end of the study, the value can be anywhere between \$1 and \$8 per megawatt-hour (2004\$). A straight line between the beginning and ending values determines the value for intervening periods. Consequently, green tag value averages \$3.50 at the beginning of the study and averages \$4.50 at the end of the study.

- **Windpower shaping costs:** Windpower shaping costs are reported to range from \$3-\$8 per megawatt hour, lower than expected several years ago. The model uses deterministic shaping costs: \$5.02 per megawatt hour for the first 2,500 megawatts of wind capacity and \$10.76 per megawatt hour thereafter (2004\$).
- **Other emission costs:** Power plant costs include the cost of the best available control technology required to meet current air emission requirements. The costs for coal-fired power plants also assume additional mercury control in anticipation of regulations currently under consideration by the Environmental Protection Agency.

The NWPCC's approach to resource planning is called "risk-constrained least-cost planning."

Given any level of risk tolerance, there should be a least-cost way to achieve that level of risk protection. The NWPCC calculates the expected net present value and TailVaR₉₀ for each plan (described above).

B-1.8 GHG REGULATION RISK

The NWPCC hired Trexler Climate + Energy Services to summarize the current state of climate change policy. The firm developed three scenarios about the probability, timing and magnitude of carbon control measures and assessed their effect on different portfolios in terms of cost and risk. These scenarios were included in the portfolio analysis.

Carbon offset costs were estimated based on state experience, NWPCC-sponsored workshops, MIT studies of the McCain-Lieberman proposal and carbon sequestration costs. To simplify modeling, a carbon tax was used as a proxy for the effects of climate change policy.

B-1.9 ENVIRONMENTAL EFFECTS

The NWPCC proposes increased integration of power operations impacts on fish populations in future planning studies.

Cost of Best Available Control Technology (“BACT”) for emissions and mercury regulation are included as variable in portfolio model. Explicit costs for emissions other than carbon are not quantified.

B-1.10 PORTFOLIO DEVELOPMENT

See Portfolio Analysis section.

B-1.11 PORTFOLIO ANALYSIS

Using above defined risk factors, the NWPCC develops portfolio models using Olivia and Excel. Crystal Ball Monte Carlo simulation is used to simulate cost distribution of portfolios. Finally, the NWPCC uses the Crystal Ball OptQuest optimization module to determine the least cost portfolio for a given risk level and thus develop an efficient frontier.

The model uses a three-year average of load growth and any change in resource capability to determine when in the future resource-load balance would cross below a given threshold. If the model needs a resource to meet anticipated future load, the criterion consults pertinent expected forward prices for each resource (not perfect foresight). If the plant would pay for itself, construction proceeds; if not, the model compares the value of the plant to that of alternatives. If the plant cannot pay for itself but is still the least expensive alternative, construction continues.

B-1.12 PORTFOLIO SELECTION CRITERIA

Efficient frontier analysis identifies least cost portfolio for given risk level. The program first seeks a plan that satisfies a risk constraint level. Once it finds such a plan, the program then switches mode and seeks plans with the same risk but lower cost. The process ends when a least-cost plan for each level of risk is found. NWPCC uses

TailVaR₉₀ risk measures. TailVaR₉₀ is the average for the worst 10 percent of outcomes (above the 90th percentile) and is a commonly used measure of risk in resource planning. The model also tracks St. Dev, VaR₉₀, CVaR₂₀₀₀₀, 90th Decile, Mean maximum annual cost increase and mean annual St. Dev.

The NWPCC does not select a single optimal cost-risk point on the efficient frontier. Instead the NWPCC offers the analysis and supporting models to Pacific Northwest utilities to assist in the development and evaluation of their individual resource plans.

B-1.13 PROCESS

The 1980 Pacific Northwest Electric Power Planning and Conservation Act established NWPCC, which is required to develop 20 year power plans at least every five years. The process is lead by NWPCC staff with extensive involvement of various stakeholder working groups, to develop assumptions, inputs and reports.

In February 2002, the NWPCC began development of its Fifth Northwest Power Plan by issuing a paper and requesting comments on elements the council thought should be addressed in the new power plan. The existing power plan dated to 1998. In response to comments on the paper, the NWPCC began developing a draft power plan. Later in 2002, and in 2003, the NWPCC developed a series of papers for public review and comment that explored in detail the elements the council planned to include in the new power plan. These included, among others, energy conservation, demand response, high-voltage transmission, forecasts of future fuel prices and demand for electricity, and the future role of the Bonneville Power Administration (“BPA”) in power supply. In September 2004, the council completed the Draft Fifth Northwest Power Plan and issued it for public review and comment. In December, after reviewing the comments, the NWPCC adopted the new power plan. The adopted plan assures the Pacific Northwest region an adequate, efficient, economical, and reliable power supply.

B-1.14 SOFTWARE

The AURORA electricity model is used for demand growth in other western areas.

The NWPCC GENESYS probabilistic model is used for modeling generation in the Pacific Northwest.

Crystal Ball Monte Carlo and OptQuest Excel add-ins are used for risk analysis and optimization.

Olivia (a program produced by NWPCC for managing and storing portfolios that are analyzed with OptQuest and Crystal Ball software) and Excel are used for tracking portfolios and performing portfolio analysis.

B-1.15 USE OF PROPRIETARY DATA

To the extent possible, data and models are made available for public review and use. This includes the portfolio model developed using Crystal Ball and Excel. For those models not publicly available (GENESYS, AURORA), data sets and results are available for public review. NWPCC encourages and supports the use of its data, models and reports on the part of groups and individuals in the region.

The NWPCC does not use utility specific data or proprietary forecasts.

B-2 PacifiCorp**B-2.1 LOAD FORECASTING**

Near-term forecasts rely on statistical time series and regression methodologies while longer-term forecasts are dependent on end-use and econometric modeling techniques. These models are driven by county and state level forecasts of employment and income that are provided by public agencies or purchased from commercial econometric forecasting services (provided by Global Insights).

B-2.2 NEEDS DETERMINATION METHODOLOGY

Both capacity and energy load and resource balances are calculated using resource levels, obligations and reserve margins (12 percent & 15 percent). Contract expirations are also considered. Various fixed near-term capacity changes are assumed.

An annual summer peak resource deficit is projected and met by additional renewables, demand side management (“DSM”), and market purchases in the near-term. In the long-term, widening capacity and energy deficits will need to be covered by base, intermediate, or both resource additions.

B-2.3 TIME PERIOD OF ANALYSIS

The 2007 integrated resource plan (“IRP”) (filed with appropriate state regulatory agencies) covers a 10-year period: 2008-2017. The IRP model has a 20-year study period capability.

B-2.4 FUEL AND ELECTRICITY MARKET PRICE FORECASTING

Natural gas forecasts are based on probability-weighted forward gas price curves; the curves are based on a weighted average of PIRA Energy’s Henry Hub low, medium, and high gas price cases.

Percentages for the low and high coal commodity cost values are based on the U.S. Energy Information Administration’s low and high delivered coal price sensitivity forecast cases reported in the 2006 Annual Energy Outlook. PacifiCorp assumed one-half of the difference between the sensitivity and reference cases to account for the fact that transportation costs, a main component of the cost forecast, are a relatively smaller portion of the delivered fuel cost in the Rocky Mountain region than for the U.S. as a whole.

Due to the strong correlation between natural gas and wholesale electricity prices, these variables were linked together as low, medium, or high values for a scenario.

B-2.5 RESOURCE COST DEVELOPMENT METHODOLOGY

Electric Power Research Institute's Technical Assessment Guide (TAG®), along with recent project experience and consultant studies, was used to develop PacifiCorp's supply-side resource options. The TAG contains information on capital cost, heat rate, availability, and fixed and variable operating and maintenance cost estimates. The data in the TAG must be customized for each application by adjusting basic financial parameters as well as physical parameters for each potential site, such as coal quality, water availability, and elevation. The 2006 TAG data were used to develop a cost and performance profile for each potential resource.

The results of the TAG runs were compared to the actual cost data from recent projects as well as internal PacifiCorp studies of site specific generation options. The TAG results were customized to give results approximately in agreement to these recent studies. The customization was primarily done for capital costs, and reflects market conditions as of late spring of 2006. The cost factors used to reflect technology risk in the uncertainty range for various resource options were taken from a U.S Energy Information Administration paper "Assumptions to the Annual Energy Outlook 2006, DOE/EIA-0554(2006), March 2006". In addition to the technology factors the TAG capital cost estimates were adjusted by 5 percent on the low end and 10 percent on the high end to give an overall range. A table summary of technologies and TAG assumptions is provided.

Quantec LLC constructed proxy supply curves for Class 1 (fully dispatchable or scheduled firm) and Class 3 (price-responsive) demand-side management programs.

B-2.6 TREATMENT OF ENERGY EFFICIENCY

DSM does not appear to be included in load forecasts, but rather modeled on an equivalent basis to supply side resources.

Demand-side management programs are divided into four general classes:

- Class 1 DSM: Fully dispatchable or scheduled firm
- Class 2 DSM: Non-dispatchable, firm energy efficiency programs
- Class 3 DSM: Price responsive programs
- Class 4 DSM: Energy efficiency education and non-incentive based voluntary curtailment programs

DSM pursuits have been expanded in terms of investment level, state presence, breadth of DSM resources pursued (Classes 1-4) and resource planning considerations.

Company investments have increased four times (from \$50 million to \$200 million) over the last five years (2002-2006) compared to the preceding five years (1997-2001) as the company has expanded DSM activity in the states of Utah, Washington and Idaho and transitioned existing DSM activities in Oregon over to the Energy Trust of Oregon.

B-2.7 MARKET PRICE RISK ASSESSMENT

A number of stochastic simulations were performed for sensitivity analysis purposes. Several of the scenarios were designed to address specific risk analysis requirements identified in the Oregon Public Utility Commission's Integrated Resource Planning guidelines and 2004 IRP acknowledgement order. The Planning and Risk Module sensitivity scenarios test the following conditions:

- Plan to a 12 percent planning reserve margin, and include a sufficient amount of Class 3 demand side management program capacity to eliminate Energy Not Served (ENS). This study addresses an Oregon Public Utility Commission acknowledgement order requirement.
- Plan to an 18 percent planning reserve margin – use the same portfolio resources selected by the Capacity Expansion Module for Sensitivity Analysis Scenario #2 (“Plan to 18 percent capacity reserve margin”)

- Using one of the risk analysis portfolios as the basis, replace a new base load resource with an equivalent amount of front office transactions to determine the incremental cost and risk impacts.
- Using one of the risk analysis portfolios as the basis, replace a base load pulverized coal resource with an IGCC plant that has minimum carbon capture provisions. Also include sufficient shorter-term resources to maintain the planning reserve margin until an IGCC plant can be placed into service.
- Using one of the risk analysis portfolios as the basis, replace a new resource with Combined Heat & Power (CHP) and aggregated dispatchable customer-owned standby generators to determine the incremental cost and risk impacts. This sensitivity addresses an analysis requirement in the Oregon Public Utility Commission's 2004 Integrated Resource Plan acknowledgement order.

See also the description of PaR Software Module below.

PacifiCorp also measures portfolio risk by subtracting the stochastic mean Present Value Revenue Requirement (PVRR) from the PVRR of the average of the 5 percent of worst outcomes (TailVaR₉₅).

B-2.8 GHG REGULATION RISK ASSESSMENT

All risk analysis portfolios were simulated with five CO₂ adder levels—\$0/ton, \$8/ton, 15/ton, \$38/ton, and \$61/ton (in 2008 dollars)—and associated forward gas/electricity price forecasts. The company modeled both a cap-and-trade and emissions tax compliance strategy, and expanded its reporting of CO₂ emissions impacts.

B-2.9 ENVIRONMENTAL EFFECTS

The following environmental issues are treated in PacifiCorp's IRP:

- Currently regulated emissions

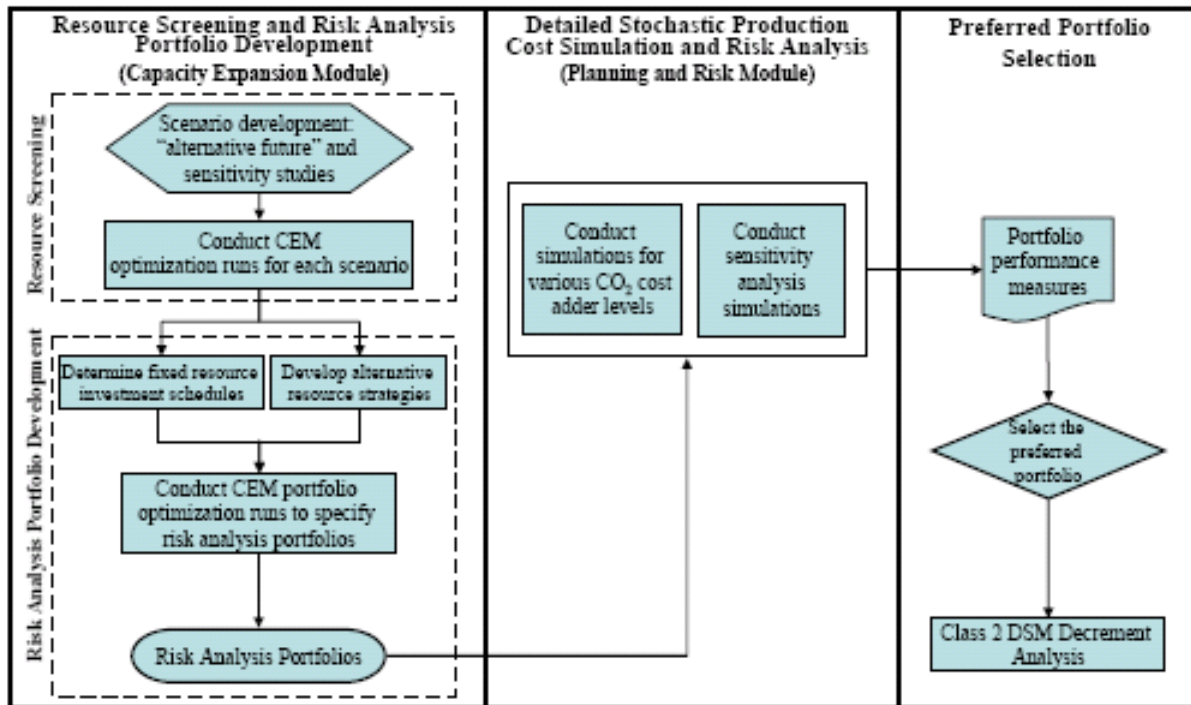
- Climate Change
- RPS requirements
- Hydroelectric relicensing

B-2.10 PORTFOLIO DEVELOPMENT

See Portfolio Analysis and Portfolio Selection Criteria sections below.

B-2.11 PORTFOLIO ANALYSIS

The 2007 IRP modeling effort consists of three phases: (1) resource screening, (2) risk analysis portfolio development, and (3) detailed production cost and stochastic risk analysis. The Capacity Expansion Module (CEM) supports resource screening and development of risk analysis portfolios. Detailed production cost simulation and associated stochastic analysis, which attempts to quantify the most significant sources of portfolio risk, are supported by the Planning and Risk (PaR) Module. The figure below characterizes the three phases in flow chart form, showing the main steps involved and how these phases are linked with the preferred portfolio selection phase (far right on the chart).



B-2.12 PORTFOLIO SELECTION CRITERIA

Portfolio selection criteria consist of:

- resource screening – the company used a Capacity Expansion Model (CEM) to evaluate generation, load control, price-responsive demand-side management, market purchases, and transmission resources on a comparable basis with the use of “alternative future” scenarios
- risk analysis
- portfolio development
- detailed production cost and stochastic risk analysis
- assistance from public stakeholders to construct the alternative future scenarios

The main purpose of these scenarios is to identify general resource patterns attributable to changes in assumptions, and to help identify robust resources—those that frequently

appear in the model's optimized portfolios under a range of futures. Alternative future scenarios capture variations in potential CO2 regulatory costs, natural gas prices, wholesale electricity prices, retail load growth, and the scope of renewable portfolio standards.

Using the results from the alternative future scenario studies, PacifiCorp defined risk analysis portfolios for stochastic simulation. Other key portfolio development criteria included diversity among the major new resource types and the impact of evolving state resource policies.

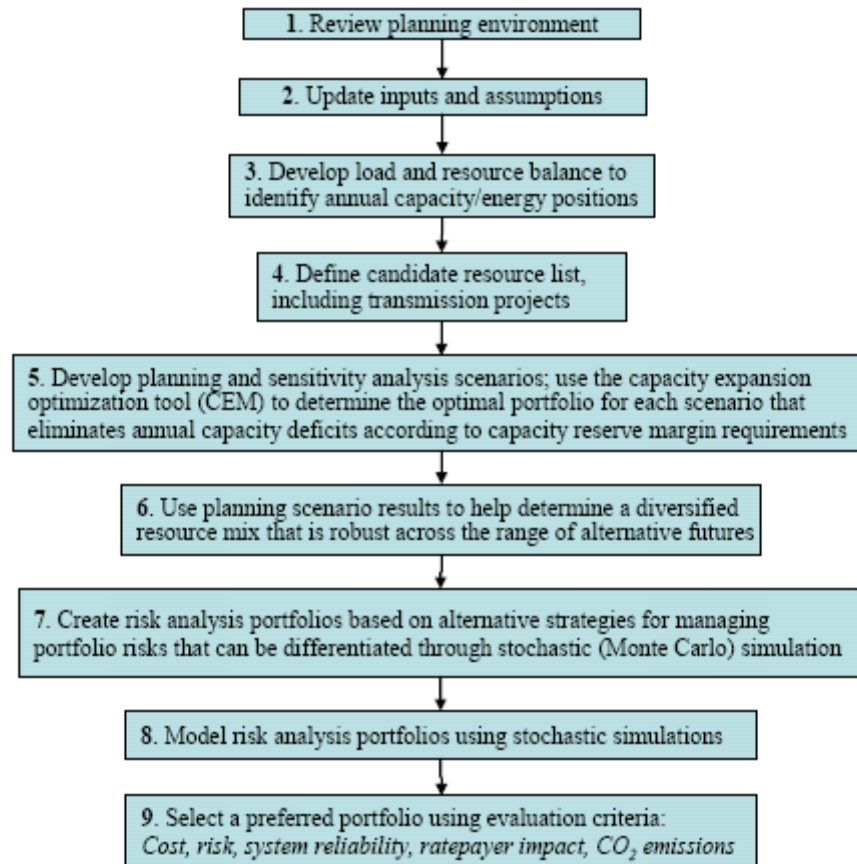
Portfolio performance was assessed with the following measures:

- stochastic mean cost (Present Value of Revenue Requirements, levelized on a per-MWh basis)
- customer rate impact, measured as the levelized net present value of the change in the system average customer price due to new resources for 2007 through 2026
- emissions externality cost
- capital cost
- risk exposure
- CO2 and other emissions
- supply reliability statistics.

The preferred portfolio is selected from among the risk analysis portfolios primarily on the basis of relative cost-effectiveness, customer rate impact, and cost/risk balance across the CO2 adder levels. The preferred portfolio represents the most robust resource plan under a reasonably wide range of potential futures.

B-2.13 PROCESS

PacifiCorp's IRP process is detailed in the figure below.

**B-2.14 SOFTWARE**

Two modeling tools: Capacity Expansion Module (CEM) and the Planning and Risk (PaR) Module.

CEM – deterministic least-cost optimization with resource options over study period.

MIN cost for existing resources subject to

- load balancing
- reliability
- other constraints.

Optimizes resource additions subject to:

- Resource investment in
 - Capacity technologies
 - DSM programs
- Transmission
- Capacity constraints
- Monthly peak loads
- Planning reserve margin for a 24-zone model topography

Builds fixed resource investment schedules for wind and distributed resources, and to optimize the selection of other resource options according to specific resource strategies.

PaR – Chronological commitment/dispatch production cost model operated in probabilistic mode to develop risk-adjusted portfolio performance measures.

Simulations incorporate stochastic risk in its production cost estimates by using Monte Carlo random sampling of five stochastic variables:

- loads
- commodity natural gas prices
- wholesale power prices
- hydro energy availability
- thermal unit availability.

B-2.15 USE OF PROPRIETARY DATA

Not discussed.

Notes:

PacifiCorp has detailed 42 scenarios in its IRP process but has been criticized by the Utah Division of Public Utilities (DPU) and the Utah's Committee of Consumer Services (CCS) as providing an inadequate number of cases. PacifiCorp replied that it cannot produce as many cases as the Utah DPU suggests ("several hundred times more than 42") and questions if this will result in recommendations for IRP non-acknowledgement. Instead, PacifiCorp proposes that consideration of trigger point analysis and risk adaptability assessment outlined in Oregon Commission staff's proposed IRP guild line 8 (Docket UM 1302) be delayed until the Oregon commission issues its order. At that time, PacifiCorp suggests a meeting with affected utilities (PacifiCorp, Portland General Electric, and Idaho Power) to discuss development of a joint approach for meeting Oregon's requirements.

B-3 Idaho Power**B-3.1 LOAD FORECASTING**

For planning purposes, the future demand for electricity by customers in the Company's service area is represented by three load forecasts: (1) a 50th percentile or expected case load forecast, (2) a 70th percentile load forecast, and (3) a 90th percentile load forecast. These forecasts define three possible load conditions evaluated in the 2006 IRP. The expected case load forecast assumes median temperatures and median rainfall. The 70th percentile load forecast and a 90th percentile load forecast were prepared to illustrate the weather-related uncertainty inherent in forecasting electrical loads. The 70th

percentile load forecast is designed such that it can be assumed monthly loads estimates will be exceeded in 3 out of 10 years do to variation in underlying variables; the 90th percentile in 1 out of 10 years.

This Sales and Load Forecast is strongly influenced by the 2006 Economic Forecast developed by an independent consultant, John Church of Idaho Economics. The 2006 Economic Forecast is based on a forecast of national and regional economic activity performed by Global Insight, a national econometric consulting firm. The Global Insight economic forecast is modified by Idaho Economics to reflect anticipated service area conditions.

The sales and load forecast is constructed by developing a separate forecast for each individual sales category. Independent sales forecasts are prepared for each of the major customer classes: residential, commercial, irrigation, and industrial. Individual energy and peak demand forecasts are developed for five special contract customers.

Peak loads are forecast via 12 regression equations and are a function of temperature, space heating saturation (winter only), air conditioning saturation (summer only), historical average load, and precipitation (summer only). The peak forecast utilizes statistically derived peak-day temperatures based on 30 or more years of climate data for each month.

B-3.2 NEEDS DETERMINATION

In connection with the market price movements to historical highs during the energy crisis of 2000 and 2001, Idaho Power reevaluated the planning criteria as part of preparing the 2002 IRP. The public, the IPUC, and the Idaho Legislature all suggested Idaho Power placed too great a reliance on market purchases based upon the IRP planning criteria. Greater planning reserve margins or the use of more conservative water planning criteria were suggested as methods for Idaho Power to acquire more firm resources and reduce reliance on market purchases during low water years.

In light of public input and regulatory support of the more conservative planning criteria used in the 2002 IRP, in the 2006 IRP, Idaho Power is again emphasizing 70th percentile water conditions and 70th percentile average load for energy planning, and the 90th percentile water conditions and 95th percentile peak-hour load for capacity planning.

The representative hydrologic conditions used for analysis in the 2006 IRP (the 50th, 70th, and 90th percentiles) are based on a computed hydrologic record for the Snake River Basin from 1928–2002.

Table 4-1 provides a summary of six planning scenarios analyzed for the 2006 IRP and the criteria used for planning purposes are shown in bold.

Table 4-1. Planning Criteria for Average Load and Peak-Hour Load

Average Load/Energy (aMW)
50 th Percentile Water, 50 th Percentile Average Load
70th Percentile Water, 70th Percentile Average Load
90 th Percentile Water, 70 th Percentile Average Load
Peak-Hour Load (MW)
50 th Percentile Water, 90 th Percentile Peak-Hour Load
70 th Percentile Water, 95 th Percentile Peak-Hour Load
90th Percentile Water, 95th Percentile Peak-Hour Load

The generation forecast includes existing and committed resources. Scheduled and forced outages are also incorporated in the forecast using historical data. Idaho Power used planned maintenance and traditional maintenance schedules to estimate scheduled outages. Forced outages were estimated using observed forced outage rates at the various facilities randomly assigned throughout the planning period.

The transmission analysis requires hourly forecasts for the entire 20-year planning period for loads and generation levels on Idaho Power's system. The hourly transmission analysis is used to quantify the magnitude of off-system market purchases

that may be required to serve the load, and determine if there will be adequate transmission capacity available to deliver the off-system purchases to the load centers.

The future resource requirements of Idaho Power are not based directly on the need to meet a specified reserve margin. Idaho Power's long-term resource planning is instead driven by the objective to develop resources sufficient to meet higher-than-expected load conditions under lower-than-expected water conditions which effectively provides a reserve margin.

B-3.3 TIME PERIOD OF ANALYSIS

Idaho Power extended the planning horizon in the 2006 IRP to 20 years. Recent Idaho Power IRPs utilized a 10-year planning horizon, but with the increased need for baseload resources with long construction lead times along with the need for a 20-year resource plan to support PURPA contract negotiations, Idaho Power and the Integrated Resource Plan Advisory Committee (IRPAC) decided to extend the planning horizon of the 2006 IRP to 20 years.

B-3.4 FUEL AND ELECTRICITY MARKET PRICE FORECASTING

The IRP's expected coal price forecast is an average of Idaho Power's coal forecasts for its Valmy and Jim Bridger thermal plants. In addition, the IRP used a Wyoming-specific coal forecast for use in modeling prices for a resource located in Wyoming and a regional coal price forecast for a non-location specific, regional coal resource. The coal price forecasts were created using current coal and rail transportation market information, private forecasts, and the Global Insight 2006 U.S. Power Outlook report.

Idaho Power does not directly forecast natural gas prices; instead it combines industry forecasts developed by outside consultants as well as forecasts from published sources. The IRP's expected gas price forecast is derived from public and private source forecasts including IGI Resources, NYMEX, PIRA, EIA, NWPCC, and U.S. Power Outlook. Each source forecast is given a weight and included in a total weighted average in order to

forecast Sumas dollars-per-MMBTU. Transportation costs are then added to the weighted average price to develop a delivered Sumas price in dollars-per-MMBTU. The transportation costs also include Northwest Pipeline's fixed and volumetric charges.

The IRP high gas price forecast was derived by trending the NYMEX and IGI Resource forecasts for the period 2006–2009. This data was then trended from 2009–2013 to achieve a \$1.00/MMBTU increase over the NWPCC high case starting in 2014 and thereafter. The IRP low gas price forecast was derived using the 2004 IRP expected case gas price forecast.

B-3.5 RESOURCE COST DEVELOPMENT METHODOLOGY

Cost inputs and operating data used to develop the resource cost analysis were derived from various sources including the NWPCC, DOE, independent consultants, and regional energy project developers. The calculations were performed assuming two levels of annual energy output. First, the levelized cost of production is shown assuming expected baseload capacity factors. Second, the levelized cost of production is shown assuming expected peaking service capacity factors.

In order to comply with the FERC's Standard of Conduct requirements, Idaho Power contracted with an outside consultant to provide the technical expertise required to evaluate and screen a range of transmission options. After the initial screening, a request was submitted on the OASIS website for Idaho Power's transmission planners to analyze the necessary upgrades for the finalist portfolios.

B-3.6 TREATMENT OF ENERGY EFFICIENCY

Idaho Power includes DSM programs along with supply-side resources and transmission interconnections in the IRP resource stack.

In November 2004, Quantum Consulting of Berkeley, California, (now Itron Inc. of Oakland, California) completed a study for Idaho Power assessing the energy savings potential within the residential and commercial sectors. The study served as the basis for

the residential and commercial retrofit program options analyzed in this IRP. The Company filed the Quantum study with the IPUC in December 2004 as an addendum to the 2004 IRP.

The assumptions and energy estimates that support the industrial efficiency program extension were developed internally by Idaho Power's engineering staff. The industrial program expansion and the residential and commercial retrofit program options were each designed to maximize the potential energy benefits of the resource while remaining cost-effective from a total resource perspective.

The cost-effectiveness analysis is the primary focus of the screening criteria. The static cost-effectiveness analysis of DSM programs at Idaho Power is performed using the methods described in the EPRI End-Use Technical Assessment Guide Manual as well as The California Standard Practices Manual: Economic Analysis of Demand-side Programs and Projects. The proposed DSM programs considered for inclusion into the 2006 IRP are evaluated from Utility Cost Test and Total Resource Cost test perspectives.

B-3.7 MARKET PRICE RISK ASSESSMENT

Each of the finalist portfolios was evaluated with respect to its exposure to market sales and purchases. Each portfolio relies on the regional market for sales when Idaho Power has surplus energy, or purchases during times when customer demand exceeds total generation. A summary of the market risk analysis is shown in Table 6-8.

Table 6-8. Market Risk Analysis

	PV of Portfolio Power Supply Cost (\$000s) ¹			
	F1	F2	F3	F4
Total Portfolio Power Supply Cost (Expected NG Price)...	\$4,829,327	\$5,051,302	\$4,938,464	\$5,054,667
Market Sales (Expected Case).....	(\$3,129,008)	(\$2,342,043)	(\$2,674,437)	(\$2,097,896)
Market Purchases (Expected Case).....	\$202,083	\$343,787	\$249,795	\$428,502
Sensitivity to a 10% Decrease in Market Sales	\$312,901	\$234,204	\$267,444	\$209,790
Sensitivity to a 10% Increase in Market Purchases.....	\$20,208	\$34,379	\$24,980	\$42,850
Market Risk	\$333,109	\$268,583	\$292,423	\$252,640
Relative Risk	\$80,469	\$15,943	\$39,783	—

¹ Based on the 20-year planning period.

Because the resource planning criteria eliminate the monthly energy deficiencies for all portfolios, under no portfolio is Idaho Power a net importer of power. Under all portfolios, Idaho Power is a net exporter of power and customers benefit from regional market sales. However, as a seller of power, Idaho Power is exposed to the risk that market prices will decline when making sales.

Details on the data, risk measures and assumptions used to quantify and model market risk are not described.

B-3.8 GHG REGULATION RISK

The expected case scenario used in the IRP assumes a cost of \$14 per ton in 2006 dollars for carbon emissions beginning in 2012. The boundary conditions used in the analysis were \$0 and \$50 per ton of CO₂ for the low-case and high-case scenarios. The costs of carbon emissions used in the risk analysis are derived from Order 93-695 from the OPUC. (Idaho Power files its IRP with both the IPUC and OPUC).

The IRP also references the PacifiCorp IRP and CPUC D. 05-04-024

Key crossovers occur at emission adder values of approximately \$13 and \$28/ton. For CO₂ adders greater than \$13/ton, IGCC with sequestration is preferred to IGCC without sequestration. However, for expected case natural gas prices, pulverized coal technologies yield the lowest levelized cost for any value of a CO₂ adder up to \$28/ton. If the CO₂ adder is increased to above \$28/ton, then IGCC technology with sequestration results in the lowest levelized cost.

B-3.9 ENVIRONMENTAL EFFECTS

In the analysis, Idaho Power incorporated estimates for the future costs of certain emissions into the overall cost of the various fossil fuel-based resources. Within the resource cost analysis ranking, the levelized costs for the various fossil fuel-based resources include emission adders for carbon dioxide (CO₂), nitrogen oxides (NO_x), and mercury. These additional costs are assumed to begin in 2012. Table 5-1 provides the

emission adder rates assumed in the analysis. Based on these assumptions, Table 5-2 provides the emissions cost per MWh for the various fossil fuel-based resources that were analyzed. Emission adders, specifically for CO₂ are discussed further in Chapter 6.

Table 5-1. Emissions Adders for Fossil Fuel Generating Resources–Base Case

Adder	Cost in 2006 U.S. dollars	First Year Applied	Annual Escalation
CO ₂	\$14 per ton	2012	2.26%
NO _x	\$2,600 per ton	2012	2.26%
Mercury	\$1,443 per ounce	2012	2.26%

Table 5-2. Emission Adders–Dollars per MWh (2006 Dollars)–Base Case

Adder	CO ₂	NO _x	Hg	Total
Pulverized Coal	\$12.26	\$0.37	\$0.46	\$13.08
IGCC	\$11.69	\$0.60	\$0.46	\$12.75
IGCC with Carbon Sequestration	\$1.76	\$0.31	\$0.46	\$3.21
Fluidized Bed Coal	\$12.26	\$0.87	\$0.46	\$13.59
Simple-Cycle CT	\$7.93	\$0.10	\$0.00	\$8.03
Combined-Cycle CT	\$5.60	\$0.00	\$0.00	\$5.60

The 2006 IRP is the policy instrument that Idaho Power is using to introduce public discussion on the questions surrounding green tags and environmental attributes. This discussion is designed to bring these questions to the attention of the public through the Idaho and Oregon regulatory commissions for resolution.

B-3.10 PORTFOLIO DEVELOPMENT

Idaho Power examined 12 resource portfolios and several variations of portfolios in preparing the 2006 IRP. Discussions with the IRPAC led to the selection of four finalist portfolios for additional risk analysis—a portfolio that emphasized thermal resources, a portfolio with a strong commitment to renewable resources, a resource portfolio that emphasized regional transmission, and a modified version of the 2004 IRP preferred portfolio. The resource portfolios were designed to explore a variety of different

resource alternatives and to analyze the costs and benefits associated with each resource strategy.

The resource portfolios varied from a portfolio with no coal-fired resources and almost 1,000 MW of new renewable resources, to a portfolio with 1,475 MW of new transmission import capacity. Other portfolios included a predominantly coal-fired portfolio which included almost no natural gas-fired generation, and a number of diversified portfolios include varying amounts of wind, geothermal, coal, simple-cycle and combined-cycle combustion turbines, and demand-side resources.

B-3.11 PORTFOLIO ANALYSIS

Each portfolio was analyzed using the AURORA^{xmp} Electric Market Model over a 20-year study period. The portfolio costs include both the cost of capital and operating costs of the various additional supply-side and demand-side resources proposed within each portfolio, as well as the cost of capital and operating costs of Idaho Power's existing and committed resources. In addition to these fixed and variable operating costs, the AURORA model determines wholesale market purchases and sales for each portfolio.

The 20-year stream of portfolio costs from AURORA were discounted to 2006 dollars using the established discount rate (6.93 percent after tax), and the resulting values from the portfolios were compared. The AURORA financial modeling assumes Idaho Power will own and operate the resources included in each portfolio throughout the planning period.

B-3.12 PORTFOLIO SELECTION CRITERIA

The 12 original portfolios were analyzed under four different scenarios:

- Expected: CO₂ adder of \$14/ton beginning in 2012, expected gas prices.
- GHG 50: CO₂ adder of \$50/ton beginning in 2012, expected gas prices.
- GHG Zero: No CO₂ adder, expected gas prices.

- High Gas: CO2 adder of \$14/ton beginning in 2012, high gas prices.

In all scenarios, it is assumed that the Production Tax Credit for wind generation continues to be renewed in its current form until 2012.

AURORA was used to estimate the portfolio costs for each of the 12 portfolios under each of the above four scenarios for the 20-year planning period. The present value of each portfolio for each scenario was calculated for the following:

- Market Purchases: Present value of each portfolio's market purchases over the 20-year planning period.
- Resource Total: Present value of the resource costs for each portfolio including resource costs associated with existing resources (ownership, fuel, and other operating and maintenance costs). Resource costs include all of the fixed and variable production costs for the portfolio
- Market Sales: Present value of each portfolio's market purchases over the 20-year planning period
- Total Cost: The summation of the three previous measures.

The above calculations yield 192 sets of results (12 portfolios x 4 scenarios/portfolio x 4 sets of results/scenario = 192 sets of results). These results were then used to rank the portfolios according to the following three criteria:

- Sales to (Purchases + Resource costs) Ratio: This ratio was calculated for each portfolio for each scenario listed above (1–4). This metric is a measure of the portfolio's reliance on (and exposure to) the market.
- Average Total Cost (PV): The present value of the total costs for each portfolio scenario listed above was determined and the resulting values were averaged for

each portfolio. $PV \text{ of Average Total Cost} = (PV \text{ Expected Total Cost} + PV \text{ GHG50 Total Cost} + PV \text{ GHGZero Total Cost} + PV \text{ HighGas Total Cost})/4$.

- Average of Resource Costs: The present value of the resource costs for each portfolio scenario was determined and the resulting values were averaged for each portfolio. $PV \text{ Average of Resource Cost} = (PV \text{ Expected Resource Cost} + PV \text{ GHG50 Resource} + PV \text{ GHGZero Resource} + PV \text{ HighGas Resource})/4$.

Idaho Power identified four of the original 12 portfolios for additional risk analysis. The four portfolios, designated as Green, 2004 IRP Preferred, Basic Thermal, and Bridger to Boise Transmission, demonstrated unique strengths and positive characteristics in the initial scenario cost analysis.

The objective of the risk analysis is to identify portfolios that perform well in a variety of possible scenarios. Each finalist portfolio was analyzed for quantitative risk associated with carbon tax, natural gas prices, capital and construction costs, hydrologic variability, and market risk. In addition, consideration was given to qualitative risks such as regulatory environment, declining Snake River base flows, FERC relicensing, resource timing and commitment, resource siting, fuel, implementation, and technology.

Idaho Power made a subjective probability assessment of the high, expected, and low scenarios.

The following impacts were considered:

- 1) No CO₂ adder, 2) a \$14 per ton adder, and 3) a \$50 per ton adder.
- Low, expected, and high forecast for natural gas prices.
- Discount rate assumptions and construction cost variances.
- Observed historical variability in hydrologic conditions was also quantified and incorporated into the analysis.

- Market risk was analyzed to assess exposure related to market sales and purchases.

The five types of risk previously addressed in the quantitative analysis are summarized in Table 6-9. In all cases, natural gas price risk is shown as a negative number, indicating a reduction in portfolio power supply costs. Hydrologic variability risk is not included in the risk-adjusted total portfolio costs shown in Table 6-9 due to the magnitude of the results.

Table 6-9. Risk Analysis Summary

	20-Year Present Value (\$000s)			
	F1	F2	F3	F4
Expected Portfolio Cost.....	\$4,829,327	\$5,051,302	\$4,938,464	\$5,054,667
Backbone Transmission Upgrade Cost ¹	\$580,956	\$525,737	\$643,867	\$394,606
CO ₂ Tax Risk (from Table 6-3).....	\$120,364	\$166,475	\$189,551	\$163,352
Natural Gas Price Risk (from Table 6-4).....	(\$88,220)	(\$63,788)	(\$87,409)	(\$37,273)
Cost of Construction Risk (from Table 6-5).....	\$104,269	\$153,217	\$159,308	\$165,986
Capital Risk (from Table 6-6).....	(\$78,433)	(\$114,027)	(\$112,334)	(\$107,314)
Market Risk (from Table 6-8).....	\$333,109	\$268,583	\$292,423	\$252,640
Risk Adjusted Total Portfolio Cost.....	\$5,801,373	\$5,987,499	\$6,023,869	\$5,886,664
Total Portfolio Cost Risk Adjusted Rank.....	1	3	4	2
Relative Risk Adjusted Portfolio Cost				
CO ₂ Tax Risk.....	–	\$46,111	\$69,186	\$42,988
Natural Gas Price Risk.....	–	\$24,432	\$811	\$50,947
Cost of Construction Risk.....	–	\$39,038	\$91,212	\$28,503
Capital Risk.....	\$35,594	–	\$1,693	\$6,713
Market Risk.....	\$80,469	\$15,943	\$39,783	–
Relative Quantified Risk.....	\$116,063	\$135,434	\$166,512	\$162,365
Relative Risk Ranking				
CO ₂ Tax Risk.....	1	3	4	2
Natural Gas Price Risk.....	1	3	2	4
Cost of Construction Risk.....	1	2	3	4
Capital Risk.....	4	1	2	3
Market Risk.....	4	2	3	1
Relative Quantified Risk Ranking.....	1	2	4	3

¹ Transmission upgrade cost not accounted for in specific portfolio resource estimates.

The goal of the risk analysis was to identify a portfolio that is resilient to the different risks; there was not specific metric or weighting of the different risk measures used to rank order the finalist portfolios.

The IRPAC and members of the public were asked to rate the likelihood of construction for each of the four finalist portfolios. After considering the risk measures and the input

of the IRPAC and public, a modified version of the 2004 IRP preferred portfolio, with some transmission upgrades, was chosen.

B-3.13 PROCESS

Idaho Power enlisted the assistance of its customers in developing the IRP through an advisory council. The council's responsibilities included:

- Representing the interests of Idaho Power's more than 480,000 customers
- Participating in open and active discussions of relevant issues, and
- Working with Idaho Power to develop ways to engage the public-at-large in the IRP process.

Idaho Power filed its 2006 IRP with the Idaho Public Utilities Commission (IPUC) in September 2006 and with the Public Utility Commission of Oregon (OPUC) in October 2006. The IPUC accepted the 2006 IRP in March 2007 and the OPUC acknowledged the 2006 IRP in September 2007. With its acceptance of the 2006 IRP, the IPUC requested that Idaho Power align the submittal of its next IRP with those submitted by other Idaho utilities. To comply with this request, Idaho Power provided an update on the status of the 2006 IRP to both the IPUC and OPUC in June 2008 and will file a new IRP in June 2009.

B-3.14 SOFTWARE

AURORAxmp Electric Market Model.

B-3.15 PROPRIETARY DATA

IGI Resources and PIRA gas forecasts.

B-4 Puget Sound Energy (PSE)

B-4.1 LOAD FORECASTING

PSE forecasts load using an econometric model based on historical data. Notable determinants include: regional and national economic growth, demographic changes, weather, prices, seasonality, and other customer usage and behavior factors. Known near-term load additions or deletions are also included; for example, because PSE is aware that two major corporations in the area plan to add facilities that will significantly increase consumption, these additions are included in the model. Retail energy price forecasts are also input into the demand forecasts, to account for their effect on consumer behavior.

For regional economic growth assumptions, PSE uses estimates provided by the AURORA model developer EPIS, which are based on information from the Northwest Power and Conservation Council and the EIA. For U.S. macroeconomic assumptions, PSE uses information and data generated by Global Insight, a global research firm specializing in economic analysis.

Electric peak loads are calculated on an hourly basis, and projected for a winter normal and extreme peak design temperatures. Gas peak loads are calculated on a daily basis using a 52-heating degree as the design day temperature to represent its relevant peak.

B-4.2 NEEDS DETERMINATION

PSE determines needs by comparing the load forecasts arrived at through the methodology described in the previous section to existing supply contracts and contract expirations.

Long-term peak resource needs are plotted over the 20-year planning horizon using the December peak-load forecast compared to the existing resources available to meet those needs. Short-term peak needs planning is performed annually, and uses monthly

estimates of peak loads and capacity for the winter period (November through February).

Short-term planning also considers the transmission capacity of each transmission link the Company owns or leases, and the current marketplace conditions for day-ahead and month-ahead purchases.

While the PSE IRP acknowledge uncertainty in hydro resources over the planning period due to contract and stakeholder issues, it is not clear how this uncertainty is taken into account.

B-4.3 TIME PERIOD OF ANALYSIS

PSE's IRP assesses energy needs looking out 20 years, and PSE performs a 20-year forecast of energy sales, customer counts, and peak demand each year.

B-4.4 FUEL AND ELECTRICITY MARKET PRICE FORECASTING

PSE relies on the economic consulting firm Global Insight for long-run fundamentals-based gas price forecasts. PSE reviews the assumptions that go into Global Insight's model and compares the forecast with other forecasts for reasonableness. For the near term (five years), PSE uses forward marks that are currently available in the market.

PSE created six scenarios for electric analysis to model a wide range of possible futures. These scenarios represent different potential price paths that may develop over the 20-year planning horizon, and price forecasts are developed for each of the scenarios. For example, in the "Green World Scenario" the gas price forecast used is Global Insight's long run high forecast, reflecting a higher demand for clean fuel.

B-4.5 RESOURCE COST DEVELOPMENT METHODOLOGY

For the Base Case, the estimated cost of generic resources is based on bids received in response to PSE's formal 2005 Request for Proposals (RFP), along with information

obtained during 2006 as part of the Company's ongoing market activity. Bid prices received were not firm and were occasionally revised upward. "All-in" costs are used.

In developing resource costs, PSE takes into account the Production Tax Credit (PTC), one of many federal subsidies related to production of nuclear, oil, gas and alternative energy. PSE's treatment of the PTC regarding its level and duration varies across the different scenarios that PSE uses in analysis.

For demand resources, PSE had already provided an extensive analysis of energy efficiency potential in an April 2005 Least Cost Plan Update. Working with stakeholders, PSE developed targets and stretch goals based on these results. In addition, PSE also issued requests for proposals (RFPs) to acquire new electric and gas efficiency resources.

PSE utilized a comprehensive screening process to aggregate demand-side resources from a potential 1700+ individual energy efficiency and other demand side measures down to five bundles: energy efficiency, distributed generation, fuel conversion, and demand response measures. Bundling of demand resources is performed using Quantec's (now Itron) cost effectiveness screening model, using a portfolio-based avoided cost approach. Quantec's model is capable of examining the benefit of demand resources based on hourly demands and hourly prices over a 20-year period, which amounts to more than 175,000 hourly data points for each of the 1700+ individual demand-resource measures. The hourly prices PSE provides to Quantec are based on AURORA price forecasts, and include adjustments consistent with PSE's cost effectiveness screening model.

B-4.6 TREATMENT OF ENERGY EFFICIENCY

Demand resources are bundled using a portfolio-based avoided cost screening approach and Quantec's cost-effectiveness screening model. The hourly prices PSE provides to Quantec are based on Aurora price forecasts, and include adjustments consistent with PSE's cost effectiveness screening model. These include T&D benefits, system benefits

charge, and line loss reduction. PSE has developed an additional adjustment called the “planning adjustment,” as described below.

PSE’s analysis finds that the incremental cost of its 2005 LCP resource strategy is approximately 40 percent more costly than if the Company were to rely purely on spot market power. The “planning adjustment” is based on the portfolio strategy from the 2005 LCP, but with updated technology costs and characteristics, fuel prices, and power prices to reflect 2007 IRP assumptions. The difference between levelized spot prices and the levelized cost of the portfolio strategy is the planning adjustment.

For evaluating Demand Response, PSE provided Quantec an annual levelized cost of capacity resources.

B-4.7 MARKET PRICE RISK ASSESSMENT

PSE created multiple scenarios for its electric analysis to model a wide range of possible futures. These scenarios represent different potential price paths that may develop over the 20-year planning horizon. Scenarios include base, green, high economic growth, low economic growth, technology improvement (The magnitude of the improvements was identified using the EIA’s *Annual Energy Outlook 2006*.)

PSE relies on Monte Carlo analysis to account for four key uncertainty factors: market prices for natural gas, market prices for power, wind generation variability, and hydroelectric generation availability.

Additionally, PSE considered annual volatility by measuring year to year changes in revenue requirements, calculating the standard deviation of those year to year changes. The final measure of volatility is the average of the standard deviation across the simulations.

B-4.8 GHG REGULATION RISK

Based on legislative and regulatory tracking, the base case assumes the federal government will institute new regulations regarding green house gases (CO₂ for modeling purposes). The Bingaman-Domenici bill, based on the National Commission on Energy Policy, is taken as a reasonable measure and a good proxy to use for assumptions concerning future green house gas regulation. The base, or Current Trends scenario, thus assumes a CO₂ charge of \$7 per ton starting in 2012, with charges increasing 5 percent per year thereafter (compared to inflation of 2.5 percent per year). The charge is assumed to apply to both new and existing resources.

Charges for multi-pollutants are based on estimates provided by the Environmental Protection Agency (EPA), and assume the Administration's "Clear Skies" initiative is enacted. Clear Skies is very similar to current EPA initiatives. Mercury regulation is not modeled directly as there is uncertainty about potential rules and costs; however, the analysis incorporates the cost of controlling mercury as part of the fixed cost for any new coal burning plants.

The risk pertaining to these estimates is modeled through scenario analysis. For example, emission charges for CO₂ are much higher in the Green World scenario, rising from \$7 per ton in 2012 for the Current Trends scenario to \$24 per ton in 2012 for Green World. Quantitative values for the charges were estimated based on the Environmental Protection Agency report cited above. The specific case is legislation named "The Clean Power Act" which was introduced by Sen. Jeffords. Multi-pollutants costs are based on legislation introduced by Sen. Carper called the "Clean Air Planning Act."

B-4.9 ENVIRONMENTAL EFFECTS

Environmental effects are discussed in an Appendix. Issues discussed include: policy statement on GHG; PSE emissions level; PSE's goal to reduce emissions rate (goal is to meet the stringent California requirements); extensive consideration of global warming,

including local effects. The orientation of the IRP with a focus on energy efficiency and RPS standards is said to reflect PSE's policy positions and environmental goals.

B-4.10 PORTFOLIO DEVELOPMENT

PSE uses a mix of computer modeling using AURORA and "by-hand" selection to develop portfolios. Portfolios are constrained by PSE's finding that "only four resource types are currently capable of producing generation in quantities large enough to impact the significant need we face over the 20-year planning horizon. These are demand-side resources, wind, natural gas, and coal."

Further, all portfolios included "significant emphasis on demand-side resources and sufficient renewable resources to meet RPS standards." PSE modeled varying RPS laws for the purpose of portfolio development as follows:

...we first identified the load forecast for each state in the model. Then we identified the benchmarks of each RPS (e.g. 3 percent in 2015, then 5 percent in 2020) and applied them to the load forecast for that state. No retirement of existing WECC renewable resources was provided for, which perhaps underestimates the number of new resources that need to be constructed. After existing and expected renewable energy resources were accounted for, new renewable energy resources were matched to the load to meet the RPS. With internal and external review for reasonableness, these resources are created in the AURORA database.

Demand-side resources were first evaluated, and then combined into various bundles for integration into individual portfolios with supply-side resource combinations.

Screening of demand resources confirmed that the range of potential results was bounded by "bookends" representing the highest and lowest avoided costs. PSE then streamlined the analysis by eliminating two demand-side bundles where all quantitative results from these two portfolios would be contained between the bookends.

Combinations of supply alternatives were constructed to provide analytical comparison groups composed of different renewable and thermal technologies. For example, combinations were constructed to test IGCC attractiveness with and without carbon sequestration, or to test heavy reliance on natural gas, or the aggressive use of renewables to meet future load requirements.

In a further feedback loop, examining the integrated portfolios raised a number of additional analytical questions that led PSE to construct four new supply portfolios as modifications of some of the original portfolios. These changes were made primarily to create equivalent comparisons of portfolios with the same amount of power bridging agreements (PBAs) in the early years. This allowed PSE to isolate the impacts of adding wind, gas, and IGCC with and without CCS over a comparable time horizon without having the results influenced by different levels of PBAs.

B-4.11 PORTFOLIO ANALYSIS

PSE considered several “critical questions” in its portfolio analysis:

- How sensitive are the demand-side portfolios to different levels of avoided costs?
- What are the key decision points and most important uncertainties in the long-term planning horizon, and when should we make those decisions?
- What is the impact if carbon sequestration technology cannot be proven commercially viable?
- What if PSE decides not to build any more coal generation?
- What is the impact of adopting IGCC technology earlier in the planning horizon rather than later?
- What if reliance on renewable energy alternatives is significantly increased?

- What is the carbon intensity under different planning assumptions?

PSE evaluated these questions using a combination of AURORA modeling and common-sense reasoning. The AURORA model, like all optimizing models, identifies the least cost resource and creates a large number of those units in the WECC on an economic basis. Often, as with coal, the unrestricted level is much greater, according to PSE, than seems reasonable given current political and regulatory realities. Hence, PSE added constraints on coal technologies to reflect present-day trends and attitudes. Specific constraints include limiting conventional coal to the central states and only to meet each state's own load growth. Starting in 2014, the only coal technology assumed to be available in the WECC is IGCC that is carbon sequestration ready, but without actual carbon sequestration installed and operating.

Portfolio rankings were found to be unaffected by the level of energy efficiency resources; thus, the final analyses focused on just one energy efficiency bundle.

To fully understand risks associated with using expected gas prices, power prices, average hydro generation levels, and expected wind generation levels, PSE evaluated these variables using Monte Carlo analysis. The Monte Carlo analysis performed 100 iterations on each of the 12 integrated portfolio combinations for the Current Trends scenario. This provided quantitative backup for the risk evaluations. Risk was assessed by taking the average of the 10 worst outcomes from the 100-draw Monte Carlo analysis. Volatility was evaluated and found to be highest where natural gas generation was most prominent. Following earlier learnings, PSE found that "since the input variables and their probability distributions are the same for all portfolios (based on historical data), it is only necessary to perform the Monte Carlo analysis for one scenario to provide the analytic insight to support the risk assessment." This further streamlined the analysis.

PSE's method for identifying and selecting the lowest cost portfolio for natural gas is different than that described above for electric, as "analysis of the gas supply and demand system is less complex than analysis of the electrical supply system. The

network of gas supply areas and market hubs, the pipeline transportation system, storage facilities, and demand areas lends itself to analysis using linear programming (LP) optimization models. In a single run, a LP model can determine the portfolio of resources that will minimize costs over the planning horizon, based on a set of assumptions regarding resource alternatives, resource costs, demand growth, and gas prices. This approach eliminates the need to develop alternative supply portfolios and to compare the resulting costs and other impacts to select the portfolio with the lowest reasonable cost.”

B-4.12 PORTFOLIO SELECTION CRITERIA

Based on Lease Expected Cost, the quantitative analysis found that cost differences between individual portfolios are small, so conclusions about which portfolio is best or second best must consider that the magnitude differentiating the “winner” is relatively small. Further, the preferred portfolio varies widely based on scenario selection. Therefore, PSE relies on a series of qualitative, as well as quantitative evaluations, to select the preferred portfolio. The process is summarized as follows:

- *Portfolios that failed to rank 4th or higher on at least one scenario were eliminated.*
Portfolios that failed to demonstrate some measure of economic advantage were considered less attractive and did not pass the screen.
- *Portfolios constructed without PBAs did not perform as well as the same portfolio with PBAs.* The hypothetical portfolios with and without PBAs were originally evaluated in order to normalize the comparisons between “lumpy” generation additions over the planning horizon. Under current market conditions, PBAs are priced below the cost of new resources, which gives them an additional advantage. Portfolios without PBAs were screened out at this stage because of this advantage.

- *Portfolios that rely on early IGCC development were eliminated.* The earliest proposed on-line date for any IGCC to appear in the region is 2014. Given the uncertainty surrounding federal regulation—and especially state legislation that may effectively prevent development of new coal resources (including IGCC)—we do not believe it is realistic to assume such plants can be brought on line so quickly. So, only portfolios featuring later stage IGCC development passed this screen.
- *All coal projects without carbon capture and sequestration (CCS) capability were eliminated.* These projects were originally included in order to quantify the risks and trade-offs associated with CCS. At this time, it is not at all clear when—or if—CCS technology will become commercially available. Once it does, significant legal and regulatory hurdles will still need to be overcome. Portfolios that included CCS were screened out on the basis that such technology is not yet commercially available. (8-5)

This screening left only two candidates. One was better in a Current Trends, the other in a Green World scenario. To choose between these two candidates, PSE found the “tipping point” – the probability that would be required to prefer one over the other. It was found that if a Green World scenario is 30 percent or more likely to happen, then portfolio x is the best choice.

PSE notes that if CCS becomes commercially viable (estimate 2012 at the earliest) then a reassessment will need to be done as coal will become a lower cost alternative.

B-4.13 PROCESS

PSE collaborated with stakeholders to develop energy efficiency program targets that were reflected in the IRP. Seven formal Integrated Resource Plan Advisory Group (IRPAG) meetings, five Conservation Resource Advisory Group (CRAG) meetings, and dozens of informal meetings and communications preceded the filing of the IRP.

Stakeholders who actively participated in one or more meetings include WUTC staff, the Public Counsel, Northwest Industrial Gas Users, Northwest Pipeline, conservation and

renewable resource advocates, the Northwest Power and Conservation Council, project developers, other utilities and the Washington State Department of Community, Trade and Economic Development (CTED).

The IRPAG is the primary means of satisfying the requirements of WAC 480-100/90-238 for public involvement. With IRPAG, PSE discussed each building block of the IRP and invited several guest speakers. IRPAG meetings are open to all comers, including individual customers and other utilities. In addition, less structured meetings: met with individual IRPAG members, on a one-on-one basis. PSE has found the combination of one-on-one meetings followed by a group meeting to be particularly helpful in generating feedback.

The CRAG was formally established as part of the settlement of PSE's 2001 General Rate Case. The CRAG specifically works with PSE on development of energy efficiency plans, targets and budgets and consists of ratepayer representatives, regulators, and energy efficiency policy organizations.

B-4.14 SOFTWARE

PSE uses two models for integrated resource planning: AURORAxmp and the Portfolio Screening Model (PSM). The Portfolio Screening Model (PSM) is a Microsoft Excel-based hourly dispatch simulation model the Company developed to evaluate incremental cost and risk for a wide variety of resource alternatives and portfolio strategies.

B-4.15 PROPRIETARY DATA

Not discussed.

B-5 Xcel Colorado / Public Service Company Colorado (PSCo)

B-5.1 LOAD FORECASTING

PSCo prepared High, Base, and Low forecasts, in accordance with Commission Resource Planning rules. The base peak demand forecast assumes median economic growth based on projections from the Center for Business and Economic Forecasting, Inc. and Global Insight Inc., and median summer peak weather conditions. High and Low forecasts are determined in such a way that PSCo estimates that there is a 90 percent chance the actual peak demands will fall between the high and the low forecast scenarios. PSCo also created an “Enhanced DSM” scenario that reflects a reduction in demand in the later years of the forecast due to more aggressive DSM.

The general escalation rate assumed for the base analysis is 1.99 percent. This rate is based on a 40 percent labor and 60 percent non-labor weighted average from Global Insight’s employment cost and producer price U.S. macro forecast from 2007-2036. The base forecast is available through 2017 with additional years to 2036 based on growth rates from Global Insight’s long-term forecast. Additional sensitivities from Global Insight project an optimistic escalation rate of approximately 1.53 percent and a pessimistic rate of approximately 4.10 percent.

Public Service’s residential and commercial and industrial sales forecasts are developed using a Statistically-Adjusted End-Use (SAE) modeling approach. The SAE method entails specifying energy use as a function of the primary end-use variables (heating, cooling, and base use) and the factors that affect these end-use energy requirements. The SAE residential sales model consists of equations for average use per customer and number of customers. Regression models are estimated using monthly historical customers, sales, weather, economics, price, and appliance saturation and efficiency trend data. The residential sales forecast is then calculated as the product of the average use and customer forecasts.

PSCo also adjusts for other local factors, such as “loss of several firm wholesale contracts and participation of two of our largest wholesale customers.”

PSCo is a summer peaking utility and has recently experienced record highs in the summer. The Base forecast assumes these records will not continue, but the possibility of global warming is addressed in the High scenarios.

B-5.2 NEEDS DETERMINATION

PSCo determines needs by comparing the load forecasts arrived at through the methodology described in the previous section, to existing owned generation and supply contracts.

PSCo gives careful consideration to contingency planning, having found after its 2003 IRP that many of the planned resources acquired through bids as part of the 2003 process did not materialize as planned. PSCo notes that “The concern over the ability for developers to be bid into a somewhat lengthy regulated process, maintain their bid prices, and be able to commit to equipment in time to allow the project to be constructed on a timely basis, is becoming even more difficult in today’s marketplace.” Because of this, the 2007 plan more fully develops PSCo’s option to build “backstop projects.” Backstop projects will follow an all-source acquisition process and will be built if a bidder fails to timely perform contractual obligations or raises the agreed upon price.

B-5.3 TIME PERIOD OF ANALYSIS

PSCo uses a 40-year planning period and 8-year Resource Acquisition Period (RAP). The RAP is set to 8 years to allow PSCo to learn from the next few years of expected rapid change in both technology and regulation before committing to resource decisions beyond 2015 . A 40-year planning period is used to make sure that costs and benefits of resources selected in 2015 are fully counted.

Historically, PSCo has files a resource plan every 4 years, but given the rapid pace of change in the industry and policy-making arena, PSCo has committed to filing its next resource plan in 2 years.

B-5.4 FUEL PRICE FORECASTING

Gas prices were developed using a blend of New York Mercantile Exchange, Energy Information Agency, Cambridge Energy Research Associates (CERA), and Petroleum Industry Research Associates (PIRA) forecasts for Henry Hub. To the Henry Hub price were added: a Colorado Interstate Gas basis; Cheyenne Hub Adjustment; price volatility mitigation component; and transportation/delivery cost. Finally, the annual natural gas prices were applied to PSCo units with a monthly profile that reflects the price changes over a typical year. All prices were escalated at 2.33 percent beyond 2030.

Coal prices were developed using a blend of forecasts from Evolution Markets, United Power, Inc., JD Energy, CERA and PIRA. An additional rail charge including fuel surcharges was developed for each coal plant delivery location. All coal prices were escalated at 2.33 percent beyond 2030.

Nuclear fuel prices are based on forecasts from Ux Consulting, TradeTech and Energy Resource International, along with a general review of the marketplace. The base forecast provides prices through mid-2016 with later years escalating at 3.0 percent. The resulting average fuel costs were then applied to the modeled generic nuclear unit.

Electric Market Prices were developed for on-peak (16 x 6) and off-peak periods using the implied market heat rates from PIRA and CERA at 4 Corners, Craig, and SPP and the estimated gas market prices. Additionally, a monthly profile was applied to the annual estimated market electric price to reflect typical monthly power price variations. All market electric prices beyond 2030 were escalated implicitly at 2.33 percent based on the natural gas escalator.

B-5.5 RESOURCE COST DEVELOPMENT METHODOLOGY

PSCo uses the Strategist expansion planning model. The model includes only a portion of the total electric system cost Public Service. A summary of the costs included and not included is as follows:

Costs Included:

- Fuel costs for all electric power supply resources (owned and purchased)
- Purchased energy costs for all electric power supply resources
- Capacity costs of purchased power
- Tolling costs of purchased power
- Capital costs for new electric generation facilities added to meet future load
- Electric transmission interconnection and upgrades cost for new generation
- Emission costs for carbon dioxide, sulfur dioxide, mercury
- Fixed operations and maintenance (“FOM”) costs for existing and new generation facilities
- Variable operations and maintenance (VOM) costs for existing and new generation facilities
- Life-extension costs for coal plants

Costs Not Included

- Remaining book value of Company owned generating units
- Remaining book value of Existing electric transmission or distribution facilities
- Capital costs for planned electric transmission upgrades or distribution facilities

- Administrative and General costs

For Concentrating Solar Thermal resources, hourly generation profiles from a generic solar trough plant with six hours of thermal storage were used in the Strategist model. The hourly profiles were generated from within the Solar Advisor Model developed by the National Renewable Energy Lab (NREL). Solar profiles from Alamosa, Colorado were employed.

For grid-connected PV, hourly generation profiles from a one-axis tracking facility based on the Boulder, Colorado resource generated from NREL's PVWatts model were used in the Strategist model.

Costs and performance characteristics of a new nuclear power plant were developed from the Department of Energy's Energy Information Administration in their Assumptions to the Annual Energy Outlook 2007.

B-5.6 TREATMENT OF ENERGY EFFICIENCY

Energy efficiency and other DSM, in the PSCo analysis, are set at a pre-determined level for the "Low" portfolio plan. This level is the minimum required to meet Commission mandates. From there, the level of DSM is ramped upward to test two additional portfolios containing Medium and High levels of DSM and renewable energy, subject to a rate impact cap. At these pre-determined levels, energy efficiency is accounted for both as an offset to load and as a cost. The levels of energy efficiency within each portfolio are locked down and not allowed to change while modeling tests for the least cost balance of remaining generation resources and sensitivity analysis.

B-5.7 MARKET PRICE RISK ASSESSMENT

PSCo acknowledges that price risk has an impact on preferred portfolio selection: "The analysis results indicate that the level of supply-side Section 123 Resources contained in the High Section 123 Plan are expected to result in an average increase in customer rates of approximately 2 percent through year 2020. These estimates are highly dependent on

the degree to which our current assumptions for fuel prices, PTC extensions, new generation costs, carbon legislation, etc. actually materialize.”

To account for this uncertainty, PSCo examined plan costs under a range of different assumptions for four key variables: sales, fuel prices, CO₂ costs, and inflation. DSM and renewable resource levels were not allowed to change under the different sensitivity tests.

For the sensitivity analysis, PSCo determined what it felt was the reasonable range of gas and coal prices, based on a qualitative assessment of the market. Sensitivities in market price and other variables (CO₂, inflation, etc.) were run both on a standalone basis and in multivariable groups. The analysis was divided into two periods: 2007-2025, representing a near-term where variables assumptions may be more accurate, and 2025-2046, representing a long-term where variables are more uncertain.

Sales forecast ranges were developed based on a Monte Carlo simulation with the economic drivers of the forecasting models varied probabilistically. Forecasts were developed for +/- one standard deviation (high and low case respectively). The High scenario also includes added load growth from a Plug-in Hybrid Vehicle forecast and a forecast of the effects of global warming. The Low scenarios include load reductions from Residential Solar installations and Compact Fluorescent Light Bulbs. PSCo ran sensitivity analyses with the high and low forecasts.

B-5.8 GHG REGULATION RISK

Possible emissions costs for CO₂ and other pollutants were explicitly considered in the analysis, as described in Environmental Effects, below. Uncertainties in carbon prices were modeled through sensitivity analysis, as described in the Portfolio Analysis section below. A high CO₂ price scenario of \$40/ton and a low scenario of \$10/ton were examined.

To estimate CO₂ price, PSCo surveyed a variety of sources including: Energy Information Administration Analysis of Lieberman-McCain S.280 - (2007); United States Environmental Protection Agency Analysis of Lieberman-McCain S.280 - (2007); Massachusetts Institute of Technology greenhouse gas policy analysis-(2007); National Commission on Energy Policy Low Carbon Economy Act analysis - (2007); EIA Analysis of Bingham 2006 Cap and Trade -(2007); and others. PSCo then levelized the price curves from the various sources for comparison and selected what it felt were reasonable Low, Medium, and High estimates for sensitivity analysis.

B-5.9 ENVIRONMENTAL EFFECTS

As required by Commission Resource Planning rules, PSCo calculated emissions levels for sulfur dioxide, nitrogen oxides, particulate matter, mercury, and CO, for new utility resources expected to be acquired during the planning period. Emissions levels were calculated under each of the three plans (Base-, Medium-, and High-levels of DSM, renewables, and IGCC).

Under the base case, emissions of CO₂ were modeled at \$20/ton starting in 2010 and escalating at 2.5 percent annually thereafter throughout the study period. CO₂ was modeled such that the cost of CO₂ emissions factored into the economic dispatch of resources (along with fuel x heat rate and variable O&M costs).

Emissions of SO₂ were modeled to reflect the current SO₂ allocations public Service has been allotted under Title IV of the Clean Air Energy Act. Emissions of SO₂ above the allowance base were priced at \$654/ton starting in 2007 and escalating to over \$2,308/ton by the end of the study period.

Emissions of mercury were modeled with an allowance base of 700 lbs from 2010-2017 dropping to 282 lbs annually for the remainder of the study period. Emissions of mercury above the allowance base were priced at \$15,300/lb starting in 2007 and escalating to \$72,700/lb by the end of the study period. Mercury allowance prices are based on an average of nine mercury price forecasts including CERA, PIRA, JD Energy

and ICF International forecasts. Excess allowances generated a revenue credit to each resource plan at the same \$/lb rate.

B-5.10 PORTFOLIO DEVELOPMENT

PSCo's portfolio development is largely directed by Commission rules. PSCo is required to evaluate three portfolios with increasing levels of DSM and renewable energy. The Low or Base portfolio must meet minimum renewable energy and DSM requirements, finding the least cost option for remaining resources. The Medium portfolio increases the amount of "Section 123" resources (DSM, renewable, and for the Medium scenario, some IGCC generation) while retiring some coal plants. The High portfolio adds even greater amounts of these types of generation, constrained by a mandated maximum retail rate impact of 2 percent.

B-5.11 PORTFOLIO ANALYSIS

The Strategist expansion planning model was used to optimize a least-cost balance of resources that meets the requirement in the Base case and the level pre-determined for the Medium case with regard to DSM and renewables.

The High case builds on the Medium case by increasing the level of specifically selected renewable resource types, subject to a maximum 2 percent rate impact. Although not specifically addressed, it would appear likely that multiple runs of the model were completed to determine the maximum level and mix of DSM, renewable, and other "Section 123" resources that could be included in the High case without exceeding the retail rate impact cap.

Once all levels of DSM and renewables were determined, they were then "locked down" in the model and the model was run multiple times to test for different assumptions regarding variables chosen for sensitivity analysis. In essence, this is a matrix analysis with Low- Medium- and High-Section 123 resource portfolios along one axis and scenarios containing variations in the sensitivity variables along the other axis.

PSCo notes that further studies are required to determine whether it is possible to accommodate the level of wind included beyond the 2015 Resource Acquisition Period, stating that in the latter years, the High portfolio should be considered a goal rather than a firm commitment at this point.

All analysis assumes extension of production tax credits for wind installed before 2016.

B-5.12 PORTFOLIO SELECTION CRITERIA

The Colorado PUC recently undertook an emergency rulemaking to modify the state's resource planning rules, moving from "least cost" planning to "cost-effective" planning. Thus, PSCo's preferred portfolio need not be the one that will minimize the revenue requirement as long as it meets the criteria for being "cost-effective." For this reason, PSCo is able to take a somewhat qualitative approach to portfolio selection.

PSCo selects a preferred plan from the three developed cases by considering each plan in light of a set of planning objectives:

- Develop a resource plan that reliably meets the need of customers at just and reasonable rates.
- Select resources that substantially reduce the amount of CO₂ emitted.
- Develop a plan that has significant fuel diversity and price stability.
- Develop innovative forms of competitive procurement that avoid the adverse accounting and credit rating impacts of purchased power contracts to keep PSCo financially healthy and electric rates reasonable.
- Position Xcel Energy Inc. and PSCo as environmental leaders in the utility industry by acquiring more renewable resources and more DSM than the minimum levels set forth the new legislation, and do so in a cost-effective manner for customers.

PSCo finds the High plan (high in DSM, renewable, and IGCC) is the preferred plan because it:

- Maximizes the accelerated selection of Section 123 Resources (DSM and renewable)
- Maintains a balance between the cost impacts to customers and environmental stewardship by keeping the incremental cost of the selection of Section 123 Resources within the 2 percent rate impact associated with HB07-1281
- Includes greater DSM than required under HB07-1037
- Provides a portfolio of resources that clearly provides a glide path or bridging strategy toward more aggressive CO₂ emission reductions in future resource plans
- Provides the greatest hedge against gas price volatility

This decision-making is partly driven by PSCo's sensitivity analysis on each of the three portfolios considered, which showed that the Medium and High plans were better at mitigating against future scenarios that include high gas prices and high CO₂ costs. Although the Low DSM and renewable plan was least cost under low gas price and low CO₂ cost futures, the extra cost of the High plan under such a future was deemed acceptable in light of the State's and PSCo's environmental goals and since it did not exceed the mandated cap of 2 percent impact on rates.

B-5.13 PROCESS

PSCo's IRP process is very much driven by regulatory mandate. In recently modified resource planning rules, the Commission requires that PSCo:

- Provide emission estimates for sulfur dioxide, nitrogen oxides, particulate matter, mercury, and CO, for new utility resources expected to be acquired during the planning period;
- Analyze the three portfolio mixes described in the Portfolio Development section above
- Report plans for complying with the state’s Renewable Energy Standard.

Based in part on this guidance from the Commission, PSCo developed the planning objectives described in the Portfolio Selection Criteria section above.

B-5.14 SOFTWARE

Strategist expansion planning model.

B-5.15 PROPRIETARY DATA

Not discussed.

B-6 Avista Energy

B-6.1 LOAD FORECASTING

Avista takes a “bottom up” approach to load forecasting, summing forecasts of the number of customers and usage per customer to produce a retail sales forecast. The company tracks four key customer classes (which correspond to rate schedules)—residential, commercial, industrial and street lighting. Residential customer forecasts are driven by population. Commercial forecasts rely more heavily on employment and residential growth trends. Industrial customer growth is correlated with employment growth. Street lighting trends with population growth.

Customer growth projections follow from baseline economic forecasts. Avista purchases national and county-level employment and population forecasts from Global Insight,

Inc. Retail price increases and elasticity (based on historical data) are taken into consideration in creating the sales forecast. A Western Interconnect-wide study was performed to understand the impact of regional markets. Avista believes that the additional efforts to develop this study were necessary given the significant impact other regions can have on the Northwest electricity marketplace.

The baseline electricity sales forecast is based on 30-year normal temperatures. Avista studied warming trends and found that extrapolating the trend finds that in 20 years summer load would be approximately 26 aMW, a 2.6 percent, higher than the Base Case. In the winter, loads would be approximately 40 aMW, or 2 percent, lower. However, it is not clear how these warming trends are taken into consideration in the forecast, if at all.

The peak demand forecast in each year represents the most likely value for that year. It does not represent the extreme peak demand. In statistical terms, the most likely peak demand has a 50 percent chance of being exceeded in any year. Relying on compound growth rates for the peak demand forecast is an oversimplification; thus, the company plans to own or control enough generation assets and contracts to exceed expected peak demand.

B-6.2 NEEDS DETERMINATION

Avista's IRP provides reviews of all existing hydro and thermal resources as well as power supply purchase and sale contracts.

Avista uses confidence interval planning to ensure it has resources adequate to meet customer energy requirements. Extreme weather conditions can affect monthly energy obligations; if the company lacks generation capability to meet high load variations, it is exposed to increased short term market volatility. Analysis of historical data indicates that an optimal criterion is the use of a 90 percent confidence interval based on the monthly variability of load and hydroelectric generation.

Avista's planning reserves are not directly based on unit size or resource type. Planning reserves are set at a level equal to 10 percent of the one-hour system peak load plus 90 MW. The 90 MW accounts for approximately 60 MW of hydro because of icing on river banks and 30 MW of Colstrip reserves because of coal handling problems in cold weather situations. This amounts to roughly a 15 percent planning reserve margin during the company's peak load hour.

B-6.3 TIME PERIOD OF ANALYSIS

Avista uses a 20-year analysis, with a focus on the first 10 years of the plan as these are the most relevant to resource acquisition.

B-6.4 FUEL AND ELECTRICITY MARKET PRICE FORECASTING

The IRP uses fuel price assumptions in the most up-to-date EPIS database, with the exception of natural gas and coal prices.

For gas prices, Avista retains several consultants who specialize in developing long- and short-term, fundamentals-based natural gas price forecasts. The company also reviews the Energy Information Association's Annual Energy Outlook (AEO) and monitors and participates in the New York Mercantile Exchange (NYMEX) forward natural gas price market.

Avista asserts that the selected consultant's forecast "included more reasonable electric generation demand, liquid natural gas (LNG) imports, and overall natural gas supply and demand balance assumptions than the other price forecasts."

In its 2007 IRP, Avista, for the first time, includes a daily adjustment from the monthly price gas forecast. The daily price curve is based on 2003 - 2006 historical daily prices.

Coal prices and coal transportation costs in this IRP rely on data provided by the Energy Information Administration (EIA) in its February 2006 fuels forecast and its 2002 transportation cost study.

Mid-Columbia electricity prices are forecasted using AURORAxmp. In general, the hourly electricity price is set by either the operating cost of the marginal unit in the Northwest or the economic cost to move power into or out of the Northwest. Monte Carlo-style analysis varied hydro, wind, load and gas price data over 300 iterations of potential future conditions. The simulation results were used to estimate the Mid-Columbia electricity market. The iterations collectively formed the Base Case.

B-6.5 RESOURCE COST DEVELOPMENT METHODOLOGY

Resource costs were estimated using AURORAxmp, an optimization model that identifies least cost resources given load requirements. Generic Aurora inputs are replaced where Avista has better data based on local conditions.

Avista models the entire Western Interconnect (WI), noting that market conditions in the different geographic areas of the WI is important because many areas are linked by transmission facilities and the regional markets are correlated. Avista's IRPs prior to 2003 relied on externally generated market price forecasts that did not consider company operations. The 2007 IRP maintains the link between the WI market and the changing value of company-owned and contracted resources. The company's portfolio value is linked to its loads, resources and contractual arrangements, both for existing and prospective resource options, and for meeting future obligations.

Avista works with ColumbiaGrid to undertake a bi-annual transmission plan with a 10-year planning horizon, considering both single-party and multi-system projects. Transmission costs to integrate new resources into the company's system were estimated by Avista's Transmission Department. Estimates were not modeled in AURORAxmp, but rather in the proprietary PRiSM model that matches different generating resources with company-specific resource requirements. Construction quality estimates were not completed for any of the transmission alternatives; rather, estimates are based on engineering judgment only.

Energy efficiency and other demand-side measures are acquired to the extent they are cost-effective, based on surrogate generation costs. Avoided costs based on the 2007 IRP, including factors such as risk and capacity, were established to determine the cost-effectiveness of and potential for program expansion.

Additionally, the company developed an RFI and RFPs for demand-side programs.

B-6.6 TREATMENT OF ENERGY EFFICIENCY

Historically, conservation acquisition levels were included as reductions to retail load. The 2005 IRP included load that will be met by programmatic conservation, as an increase to load, and then displays the conservation resource separately. As mentioned above, avoided costs were established to determine the cost-effectiveness of and potential for program expansion. Factors considered include the avoided cost of energy and carbon emissions, reduced volatility, reduced transmission and distribution system losses, and the value of deferring capital investments for generation and transmission and distribution. This IRP evaluation is the first time that Avista has specifically incorporated the value of capacity contribution (transmission, distribution and generation) into the overall avoided cost.

B-6.7 MARKET PRICE RISK ASSESSMENT

This IRP utilizes a Base Case with an underlying set of assumptions to anchor the modeling effort. The Base Case is then modified with “futures” and “scenarios” to test the PRS under alternative conditions. *Futures* are defined by Avista as stochastic studies using a Monte Carlo approach to quantitatively assess risk around an expected mean outcome. *Scenarios* are defined by Avista as deterministic studies that change a significant underlying assumption to assess the impact of that change. Scenario results are easier to understand and require less analytical effort than futures, but they do not quantitatively assess the variability or risk around the expected outcome.

The IRP models include several key assumptions that are modeled stochastically, including natural gas, hydro, load, wind, forced outages, and emissions charges (SO₂, NO_x, Hg and CO₂).

The 2007 IRP simulates 300 hourly iterations or “games,” using the AURORAxmp for the years 2008-2027. The company prepared four stochastic futures for the IRP, consuming 8,500 hours of central processing unit time and creating a 450 gigabyte SQL database.

There are several approaches for stochastically modeling natural gas prices, as well as a number of assumptions that need to be made. The Base Case assumes 30 percent volatility (based on historical forward market price volatility) to capture projected market risk. The Base Case distribution is assumed to be lognormal based on a statistical review of the forward price datasets.

For regional analyses, wind variability is modeled in a manner similar to how AURORAxmp models hydroelectric resources. A single wind plant and generation shape is developed for each area. This generation shape is smoother than individual plant characteristics, but closely represents how a large number of wind farms across a geographical area would operate together. This simplified wind methodology works well for forecasting electricity prices across a large market, but it does not represent the volatility of specific wind resources that the company might select. A different wind shape was used for each company resource option in each of the 300 Monte Carlo iterations. This analysis uses historical wind data for potential wind sites in the Columbia Basin and eastern Montana.

B-6.8 GHG REGULATION RISK

Carbon emissions are included in the Base Case for the first time in this IRP cycle, as Avista believes that some form of market-based GHG legislation is inevitable. The National Commission on Energy Policy study, completed in late 2004, provided the basis for pricing carbon emissions in the Base Case. To quantify potential risks inherent

in a higher carbon emission cost scenario, the company looked to an Energy Information Administration study of the McCain-Lieberman Climate Stewardship Act.

The company introduces CO₂ emission charges in 2015. Recent developments in GHG legislation lean toward an earlier start date, but 2007 IRP modeling was substantially complete before recent Congressional activity began. Upon review of the modeling results, the company does not believe that adding charges sooner would in any way impact its Preferred Resource Strategy.

CO₂ is modeled based on a probability distribution of the 300 Monte Carlo iterations of AURORAxmp run for the Base Case. The mean value of the probability distribution equals the projected cost of the National Commission on Energy Policy recommendations in their 2004 study. The projected costs from that study have been escalated to account for inflation.

B-6.9 ENVIRONMENTAL EFFECTS

Avista created a Climate Change Council (CCC) to track environmental and GHG issues. The core team of the CCC includes members from the Environmental Affairs, Government Relations, Corporate Communications, Engineering, Energy Solutions and Resource Planning departments.

The main emissions concerns for resource planning involve balancing environmental stewardship and cost effectiveness, and mitigating the financial impact of emissions risks. The 2007 IRP focuses on four types of emissions that are significant to electric generation: SO₂, NO_x, Hg, and CO₂.

SO₂ is based on historical data, and the NO_x market will operate in a similar way, so the modeling follows. Mercury is somewhat problematic to model because trading does not begin until 2010 and many states have decided to opt out of the national trading market under CAMR. Projections of mercury costs are not readily available. The IRP bases its

cost estimates on a variety of governmental and private sources. CO₂ estimates are derived as described in the GHG Regulation Risk section above.

Mercury, SO₂, and NO_x are modeled using a lognormal distribution, whereas CO₂ modeling is based on Monte Carlo analysis as described in the GHG Risk section above. For stochastic analysis, each emission price was assumed to have a 20 percent standard deviation.

B-6.10 PORTFOLIO DEVELOPMENT

Portfolio development begins with planned resources and remaining resources needed are modeled by Aurora, using two methods. The first method adds resources to meet future load growth for the West by using expansion logic in AURORA_{xmp}; the second method adds generation needed to meet active or impending renewable portfolio standards (RPS).

Four “futures” were developed to stochastically model a Base Case, Volatile Gas Case, Unconstrained Carbon Case, and a High Carbon Charges Case. In each of these cases mean values and confidence ranges were estimated for electricity prices. The majority of variability was found to be a result of variation in gas prices.

In addition, seven scenarios were modeled for the 2007 IRP:

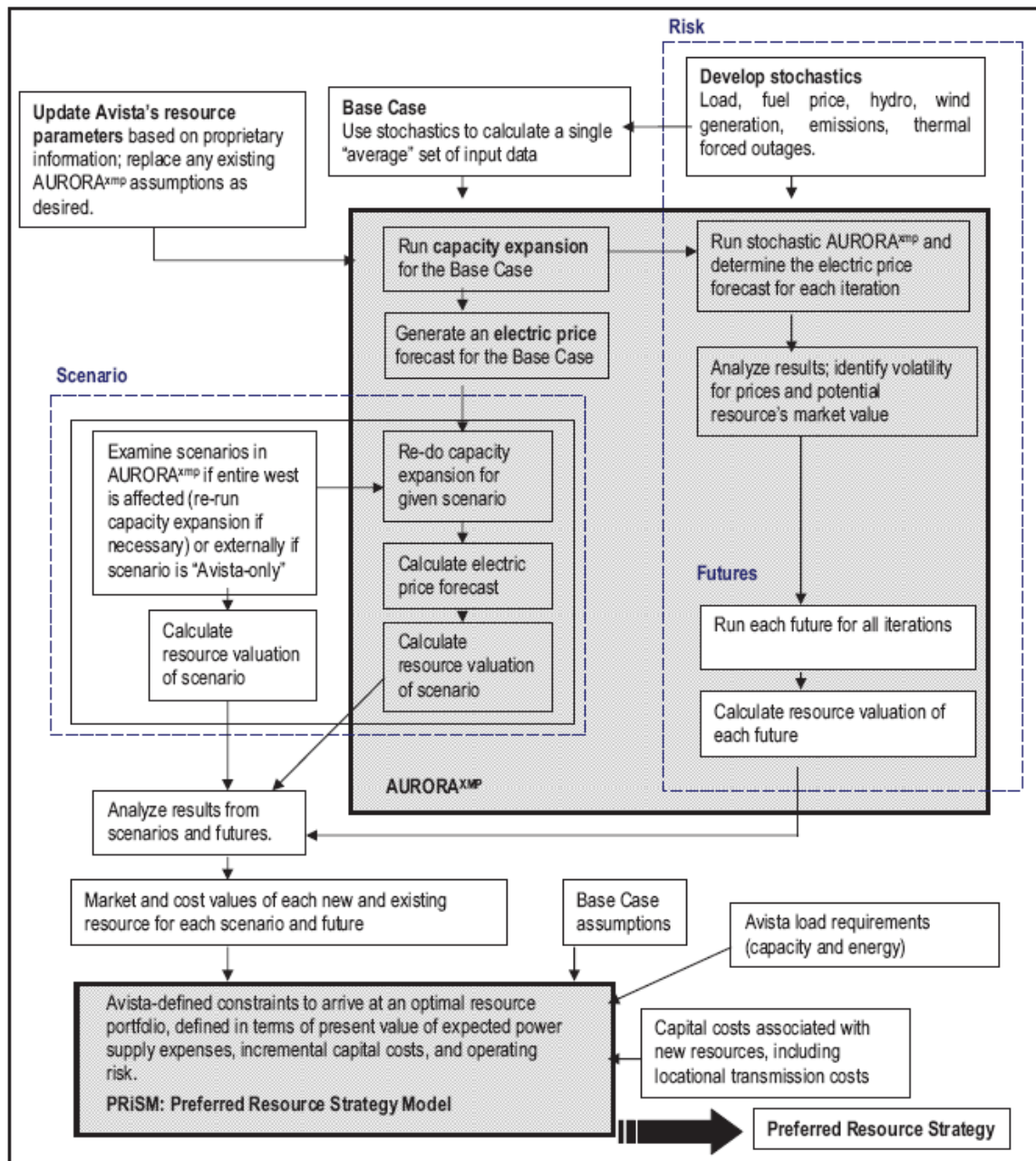
- Constant natural gas prices,
- 20 percent decrease in gas price escalation,
- 20 percent increase in gas price escalation,
- Western Interconnect loads increasing 50 percent faster,
- Western Interconnect loads decreasing 50 percent slower,
- Nuclear plant availability beginning in 2015 and

- Electric car.

The model selects qualified resources even if they are more expensive than other alternatives, provided that the additional cost does not exceed 4 percent of overall utility revenue requirement. Where costs are more expensive, the model can instead purchase qualified green tags; however, in the absence of a liquid forward market in green tags, their value is assumed to equal the 4 percent cap.

B-6.11 PORTFOLIO ANALYSIS

Avista used AURORA_{xmp} to model hourly operations for the entire Western Interconnect. The company performed 300 iterations of Monte Carlo market analysis with varying wind, hydro, load, natural gas prices, emissions and thermal outages for each evaluated future. The 300 Monte Carlo iterations are used as inputs into the Preferred Resource Strategy Model (PRiSM). The full process is shown in the figure below.



Avista Corp, 2007 Electric IRP

B-6.12 PORTFOLIO SELECTION CRITERIA

Avista develops an efficient frontier to address two key challenges – cost and risk mitigation. An efficient frontier finds the optimal level of risk given a desired level of cost and vice versa.

By definition, points on the efficient frontier are all optimal. The chosen point – that is, the chosen weighting of risk and expected cost – depends on the level of risk the company and its customers are willing to accept. Avista has determined the desired weighting to be 75 percent cost and 25 percent risk.

A number of resource constraints were necessary to ensure the PRiSM model selected a reasonable portfolio. The following list of resource constraints were placed on PRiSM:

- Wind acquisition is limited to 100 MW of nameplate capacity each year.
- Only carbon-sequestered coal plants are allowed.
- Acquisition of other renewables is limited to 35 MW over the first 10 years and 45 MW over the last 10 years.

The model can sell in the short-term electricity marketplace up to 25 MW in all years except 2017 and 2018, where expiration of the PGE Capacity Sale creates a 150 MW capacity surplus that must be managed through a larger sale in that year.

The exact PRiSM-selected portfolio strategy cannot be used because the model selects resources in perfect quantities to meet resource deficits. It also lacks the ability to quantify all of the experience of Avista's management team. Actual resource acquisition will likely not be so perfect and will be acquired in a lumpy, or stepwise, pattern. The key difference between the PRiSM-selected portfolio and the PSCo preferred portfolio is that resources added between 2011 and 2013 by PRiSM are added in 2011 as a single block in the final preferred portfolio. Resource selections in the second 10 years of the

plan are not changed from the PRiSM model selection. Acquisitions in this timeframe will be quantified in future plans.

B-6.13 PROCESS

Avista actively seeks input from constituents. The company sponsored 5 meetings of a Technical Advisory Committee (TAC), made up of customers, Commission Staff, consumer advocates, academics, utility peers, government agencies and interested internal parties. The TAC provided significant input on modeling, planning assumptions and the general direction of the planning process.

B-6.14 SOFTWARE

Preferred Resource Strategy Linear Programming Model (PRiSM).

AURORAxmp

B-6.15 PROPRIETARY DATA

Not discussed.

B-7 Arizona Public Service (APS)

APS is the largest electric utility in Arizona, one of the fastest growing states in the nation. Its estimated customer demand in 2008 is 8000 MW, its capacity requirements grow by approximately 300 MWs per year and its energy requirements grow by approximately 1,200 gigawatt hours (“GWHs”) per year. Until approximately 2015, APS expects to meet its needs by expanding its energy conservation and renewable energy programs, with the balance of needed supply coming from newly-acquired or contracted natural gas-fired generation.

The Arizona Corporation Commission (ACC) has implemented a RPS, which is currently being challenged. It has also directed Arizona utilities to consider natural gas

storage as an integral component in the development of a diverse natural gas supply portfolio, and has indicated that plans for natural gas infrastructure should be developed on a long-term basis.

Currently, there is no formal resource planning process in Arizona. The Arizona Public Utilities Commission is currently engaged in a resource planning workshop process, which APS is confident will result in formal rules that will define a resource planning process. However, because planning needs are immediate, APS has voluntarily submitted a planning document intended to “commence a transparent and collaborative dialogue on APS resource alternatives.”¹

B-7.1 LOAD FORECASTING

APS develops a population based forecast. APS does not provide information in its planning document regarding the method for developing the forecast.

B-7.2 NEEDS DETERMINATION

APS needs are reviewed every three years. A forecast of need is developed for the planning period. APS maintains a planning reserve margin of 15 percent, obtains a small amount of capacity and energy from DSM programs, and must comply with an RPS standard that was adopted by its Commission. APS currently has initiated a stakeholder process for selecting needed resources.

B-7.3 TIME PERIOD OF ANALYSIS

APS has a designated short-term planning period from 2008-2015. Resources considered for this planning period are current technologies and purchased power. APS’ long-term planning period is 20 years. Base-load resources (long-lead time) and resources that are expected to be developed in the future are considered (IGCC, Nuclear) in this period.

¹ Arizona Public Service, Resource Alternatives Report, January 2008, p.5.

B-7.4 FUEL PRICE FORECASTING

APS develops coal price projections that are based upon long-term fixed price contracts. Natural gas forecasts are based upon a snapshot of Nymex forward market prices through 2019. The forecast for the remaining years of the planning study is based upon an escalation factor of approximately 3 percent per year.

B-7.5 RESOURCE COST DEVELOPMENT METHODOLOGY

APS completes a quantitative (dollars/kw) and qualitative assessment of available resource technologies including conventional, renewable, energy efficiency, and future technologies. To assess potential resource acquisitions, the Company considers a number of qualitative factors, including: whether the resource would increase fuel diversity; its impact on reliability; environmental impacts; whether the resource would promote stable electricity prices; indirect costs associated with needed transmission investments, and; integration and operating expenses. The Company also examines and balances other, more qualitative factors, such as risk and project viability.

B-7.6 TREATMENT OF ENERGY EFFICIENCY

DSM expenditures are relatively small - \$48 million over a three year period. Budget levels for DSM programs are approved by the Commission. APS hired a consultant to estimate the potential level of capacity and energy that could be generated from DSM programs.

While scenario analysis studies include comparisons of cases with incremental increases in energy efficiency programs to other resource alternative cases, DSM results are not derived using an IRP process.

A forecast of energy derived from DSM programs is done separately from APS's load forecast. This forecast captures changes in building codes and appliance efficiency standards. Energy savings are modeled as an offset to load.

B-7.7 MARKET PRICE RISK ASSESSMENT

As part of its planning analyses, APS prepares a detailed evaluation of market conditions, and considers the existing and the projected transmission network in Arizona. Limited information is publicly available regarding APS's market price risk assessment.

B-7.8 GHG REGULATION RISK

APS scenario analysis addresses CO₂ in a limited way. CO₂ is not modeled as a production cost but as an after dispatch adder. APS used \$25/ton for CO₂ tax as a stress test in its scenario analysis.

B-7.9 ENVIRONMENTAL EFFECTS

APS' resource planning process has a limited consideration of environmental effects. APS quantifies the magnitude of emissions but only monetizes regulated emissions such as mercury. Water usage is also considered.

B-7.10 PORTFOLIO DEVELOPMENT

Portfolio development at APS is based upon the judgment of its resource planning personnel. APS selects several prominent resource alternatives to develop into future resource scenarios. These alternative resource scenarios are used to illustrate the economics, risk trade-offs, and policy issues inherent in the resource planning process. These alternative resource scenarios provide a simplified comparison of the available resource choices by illustrating each resource choice in isolation. The selected scenarios include: portfolio expansion with natural gas, renewable resources, nuclear resources, coal resources and energy efficiency resources.

B-7.11 PORTFOLIO ANALYSIS

Each of the resource scenarios was simulated using APS's production cost model to assess the economics and the key risk parameters (natural gas consumption and CO₂ emissions). Additional expansion plans are selected based upon judgment.

B-7.12 PORTFOLIO SELECTION CRITERIA

APS considers the impact that all resource alternatives have on its customers. Reliability is its primary criteria. In addition, APS gives substantial consideration to the financial impacts of any system change on customers, including rate levels, the timing of cost impacts, and exposure to price volatility. Portfolio alternatives are compared based upon economics and sensitivities to changes in natural gas and CO2 prices. APS had not selected a particular portfolio as a result of analysis at the time of our review, but rather presented the results of its analysis to the Commission and stakeholders for feedback.

B-7.13 PROCESS

Currently, there is no formal resource planning process in Arizona. The Arizona Public Utilities Commission is currently engaged in a resource planning workshop process, which APS is confident will result in formal rules.

APS believes that stakeholder collaboration is important in addressing the appropriate resource mix for the future. APS' stakeholder process is open to anyone.

B-7.14 SOFTWARE

PROMOD IV

B-7.15 PROPRIETARY DATA

Resource planning is not required in Arizona. APS' publicly available information includes projections of load through the planning period. It does not include fuel information or operating data.

B-8 Nevada Power / Sierra Pacific Power (NPC/SPCC)

NPC and SPCC are owned by Sierra Pacific Resource. The utilities follow the same regulations and use the same personnel to prepare resource plans. There is no

distinguishable difference between the resource planning processes used by the two companies.

NPC has a less than 50 percent capacity factor and has had to address high load growth almost continually for the last 15 years even with the addition of many new generating resources. NPC currently has, and likely will continue to have, a large open position. SPPC has a higher capacity factor, greater than 70 percent and a more moderate growth level. The combined peak load for the two utilities is between 7500 and 8000 MW.

NPC and SPPC are required to submit short-term energy procurement plans with their resource plans. These “Energy Supply Plans” cover a period from one to three years and must balance the objectives of minimizing the cost of supply, minimizing retail price volatility and maximizing the reliability of supply over the term of the plan. The criteria used to evaluate the effectiveness of the risk management strategy include the following metrics: test period mark-to-base, value-at-risk, portfolio below investment grade, portfolio weighted average credit rating, counterparty credit limit ongoing transactions, and counterparty credit limit large transactions.

The Nevada regulations also include incentive provisions. These provisions allow the utility to request “critical facility” status for certain resources and allows the PUCN to grant incentives to resources so designated based on the incentive criteria included in the regulations. Incentives include but are not limited to favorable accounting treatment such as CWIP in rate base and an enhanced rate of return. With the incentive regulation, the PUCN essentially has the authority to increase the attractiveness of one resource over another. For example, the PUCN could grant an enhanced rate of return for renewable resource investment or for resources that increases the diversity of a utility’s portfolio or deny an incentive for a conventional resource such as a gas fired combined cycle.

B-8.1 LOAD FORECASTING

NPC/SPPC's Load forecasts are population based and are derived using the following: UNLV Center for Business and Economic Research (CBER); population forecast; projections for hotel/motel room additions through 2012; econometric forecasts of energy need by customer class; weather data; historical sales by class and projected DSM reductions; other local factors that affect customer demand and energy use (e.g. customers leaving system, new business, and; effects of new state legislation (requirements affecting energy conservation levels). The forecasts do not include effects of: new energy efficiency standards for appliances or new building codes.

B-8.2 NEEDS DETERMINATION

The Companies' needs are derived from the demand forecast (including losses) plus reserve margin less existing company owned or controlled resources less capacity and energy from energy efficiency programs. Generation retirement is also considered in the needs determination.

B-8.3 TIME PERIOD OF ANALYSIS

Resource planning regulations in Nevada require a 20-year planning period. However, in addition to the 20-year period, the utilities voluntarily provide a 30-year analysis.

NPC and SPPC are required to submit short-term energy procurement plans with their resource plans. These "Energy Supply Plans" cover a period from one to three years and must balance the objectives of minimizing the cost of supply, minimizing retail price volatility and maximizing the reliability of supply over the term of the plan.

Commission approval of resource planning action items is limited to costs and projects included in the three-year action plan.

B-8.4 FUEL PRICE FORECASTING

The natural gas and purchased power price forecasts were derived using the average of market quotes for a given (unspecified) time period, blended with a fundamentals

forecast provided by Ventyx. The coal price forecast is based upon a custom forecast that was developed by an independent consultant.

B-8.5 RESOURCE COST DEVELOPMENT METHODOLOGY

NPC and SPPC have recently constructed, or are in the process of constructing, combined cycle and combustion turbine generating resources. They have also just refreshed their cost estimate to develop and construct a coal-fired generation resource. The estimate for the coal fired resource was based upon bids received from OEMs and contractors. Resource cost estimates for proposed generation equipment are currently developed based on recent construction cost experience and by obtaining refreshed cost estimates from manufacturers and owners/engineers. Renewable resource costs are obtained from the results of RFPs that are issued annually.

In the past, NPC and SPPC have used resource cost development software, such as EPRI SOAP, to develop generic resource cost estimates but have abandoned this practice. They have done so because of their recent experience constructing their own generating resources and the unreliability of accurate cost estimates produced by these programs due to the worldwide volatility of commodity and construction cost prices.

B-8.6 TREATMENT OF ENERGY EFFICIENCY

Nevada regulation provides for very favorable rate treatment of approved expenses for energy efficiency programs. DSM expenditures are treated similar to “plant” from a ratemaking perspective and also receive a 5 percent added return on investment. The commission has adopted the TRC test as the benchmark for approval of DSM programs. Therefore, all programs that pass this test are essentially approved by the commission. Consequently, the level of DSM selected by the utility is not determined by an IRP process. Capacity and energy derived from DSM programs is modeled as an offset to forecasted demand and energy. NPC does not consider multiple DSM portfolios. At this point it is trying to expand its DSM program and doing this with regulatory support.

B-8.7 MARKET PRICE RISK ASSESSMENT

NPC/SPPC's resource plans include a Market Fundamentals section. This section includes consideration of the effect of market forces on: natural gas prices and gas supply; natural gas transportation availability; purchase power prices; WECC-wide resource adequacy; demand by others, and; likely construction of new generation and energy efficiency measures by others.

The companies also complete an assessment of regional resource adequacy for future needs including availability of purchased power, gas transportation, gas storage and, to some extent, out-of-control area electric transmission capacity.

B-8.8 GHG REGULATION RISK

NPC and SPPC's consideration of GHG regulation risk is limited. The value they assume for a CO2 tax is not modeled as a production cost in any of the scenarios they investigate. It is worthwhile to note that the companies are trying to develop a large coal fired generating station and are only considering the addition of this resource and natural gas fired generating resources in their expansion plans. Renewable generation is limited to an amount that is just enough to meet RPS requirements based on current economic projections for these resources.

B-8.9 ENVIRONMENTAL EFFECTS

The companies are required to assess the environmental effects of each expansion plan that they consider. Commission approved externality values are used for this purpose. Externalities costs, which in NPC/SPPC's case include the assumed cost for CO2 emissions, are added after dispatch and a Present Worth of Societal Cost is determined for each alternative case.

B-8.10 PORTFOLIO DEVELOPMENT

Portfolios are developed by the Utility typically with limited input from stakeholders. The companies consider the following when developing their proposed portfolio

alternatives: resource need (base load, intermediate load and peaking), resource cost, technology maturity, availability of purchased power, RPS requirements, environmental, siting and other factors, reliability, resource risk, rate stability, resource diversity and the availability of capacity and energy from cost effective energy efficiency programs.

B-8.11 PORTFOLIO ANALYSIS

NPC/SPPC use PROMOD IV, capital expense recovery software and qualitative factors to assess the merits of each expansion plan they consider. Emission factors typically have little or no effect on portfolio selection.

Selected expansion plans are tested for sensitivities to changes in the load forecast (low, base, and high), fuel and purchase power prices.

B-8.12 PORTFOLIO SELECTION CRITERIA

Portfolios are selected based upon the following criteria: least cost, risk mitigation, rate stability, reliability and other qualitative factors. The companies must provide justification for selecting expansion plans that are not least cost.

B-8.13 STAKEHOLDER PROCESS

As indicated above the companies have an almost closed stakeholder process for supply-side resources. In most cases unsuccessful IPP or Renewable developers have no chance to participate in the resource planning process. Regulation only allows for pre-IRP filing meetings with the Commission staff and the Bureau of Consumer Advocacy.

The development of the companies' DSM programs is open to stakeholders. In fact, an organization was formed, DSM Collaborative, to help develop the companies' DSM programs. The DSM Collaborative meets monthly, includes participation by DSM experts, is effective at developing and improving the companies DSM programs and is supported by the Public Utility Commission of Nevada.

B-8.14 SOFTWARE

NPC and SPPC use PROMOD IV and capital expense recovery software to determine the cost of each resource and expansion plan that is considered. The companies use Portfolio Pro for evaluating the merits of DSM programs. An econometric model and HELM are used for developing load forecasts.

B-8.15 PROPRIETARY DATA

NPC/SPPC use proprietary data in preparation of the resource plans and amendments. This data is not made available to the public but can be obtained with a confidentiality agreement. Loads and resource tables, load forecasting information, general information about resources, methodologies for evaluating resource options, results of analysis, etc. are included in the plan. Fuel forecasts, consultants' reports, certain contractual information (operating cost, price), production cost information, financial data, construction cost estimates, etc., are considered proprietary and are excluded from the public filings.

B-9 Public Service Company of New Mexico (PNM)

Public Service of New Mexico (PNM) serves about 487,000 electricity customers and also sells electricity on the wholesale market. Its peak demand is approximately 1900 MW. Formal resource planning is just getting started in New Mexico, with PNM in the process of developing its first resource plan. The primary purpose of resource planning in New Mexico is for the utilities to provide a high level view of the resource planning process for Commission's acceptance. As such, resource plans do not include a specific request by the utility for approval of resources. If accepted, the plan becomes the basis for approval of specific requests for new resources.

The goal of the IRP process is to develop a portfolio of resources that are cost effective, environmentally conscious, and reasonably reliable. IRP filings are due every three years.

B-9.1 LOAD FORECASTING

PNM's demand forecast is based on population and assumptions regarding use per customer. It develops a low-, two mid-, and one high-load forecast.

B-9.2 NEEDS DETERMINATION

PNM uses a stakeholder process in conjunction with its demand forecast, knowledge of capacity available from existing resources, reserve margin criteria, and State energy efficiency and renewable energy mandates to determine its needs.

PNM develops an energy efficiency and a renewable energy forecast to keep track of required levels of these resources through the planning period.

PNM also considers reserve sharing arrangements with other utilities.

B-9.3 TIME PERIOD OF ANALYSIS

PNM uses a 20-year planning period with a 5-year action plan.

B-9.4 FUEL PRICE FORECASTING

Natural gas forecasts are based upon end of 2007 price projections. PNM added a fourth projection that was based upon rising natural gas costs. Coal price forecasts are derived from price estimates for Powder River Basin coal, plus coal transport, plus an escalator.

B-9.5 RESOURCE COST DEVELOPMENT METHODOLOGY

PNM considers all feasible resources and develops "Generic Level" cost estimates for these resource alternatives. Cost estimates for new resources include transmission cost estimates to interconnect the resource to PNM's electric system. Resource cost estimates

reflect an assumption that PNM will build all facilities. Costs are derived from EPRI TAG and are modified to fit PNM financial assumptions and site conditions.

B-9.6 TREATMENT OF ENERGY EFFICIENCY

New Mexico's Efficient Use of Energy Act ("EUEA") and the EE Rule require utilities to include cost effective energy efficiency and load management programs in their resource portfolios. EUEA requires utilities to deliver energy savings of 5 percent by 2014 and 10 percent by 2015 based on 2005 sales.

PNM indicated that EE resources were modeled to include the benefit of reducing system load including distribution losses. PNM modeled three levels of energy efficiency deployment plus a fourth sensitivity level. The three levels are based on scenarios defined in the Potential Study, which was vetted through public process and agreed to by various parties.

The level of DSM does not fall out of the IRP process.

B-9.7 MARKET PRICE RISK ASSESSMENT

PNM tests its preferred expansion plan and alternatives for sensitivities that simulate market price risk for various factors (see below). PNM's latest IRP assumes no new transmission lines are being built, that there are no issues with gas transportation or gas supply, and no excess transmission capacity to access purchased power. In addition, all new resources are assumed to be developed within PNM's electric system and the IRP process does not include planning for sales to others or construction of transmission lines to facilitate those sales.

B-9.8 GHG REGULATION RISK

PNM assesses the potential impact of CO₂ regulation in its scenario analysis. See below.

B-9.9 ENVIRONMENTAL EFFECTS

Emission levels (lbs/MWh) for commonly considered emissions such as SO₂ and NO_x are calculated for each resource alternative, but only CO₂ emissions are considered in the modeling. PNM also considers water usage when assessing resources.

B-9.10 PORTFOLIO DEVELOPMENT

PNM's process includes stakeholder input on all IRP decisions including portfolio development. PNM eliminated technologies that are not feasible in New Mexico (such as power from ocean waves) and built a list of resources through subsequent stakeholder meetings. Additionally, certain resources were limited based on fuel supply (biomass and geothermal) and technical constraints (wind regulation).

PNM developed a list of 27 scenarios with the help of stakeholders in a Public Advisory process. Each of the 27 scenarios is further divided into 3-5 energy efficiency cases, creating approximately 90 cases (or scenarios). The Strategist expansion planning model was used to develop portfolios for each case/scenario, with up to 5,000 portfolios generated for each case, implying consideration of up to 450,000 portfolios across all cases.

B-9.11 PORTFOLIO ANALYSIS

PNM uses scenario, qualitative and stochastic analyses to evaluate its portfolio alternatives.

With regard to scenario analysis, PNM developed a list of 27 scenarios needed to develop its integrated resource plan. The PNM draft IRP states that, "The goal of the Scenario Analysis was to define the impacts to the selected resource portfolio(s) that certain system conditions would create if they were to occur during the 20-year planning horizon. The scenario analysis focused on the following system conditions and changes thereto:

- **Load.** Mid, High and Low Forecasts, with High and Low load factors on the Mid Load forecast.
- **Natural Gas Prices.** Mid, High and Low forecasts;
- **Carbon Reduction Initiatives** beginning in 2010, and escalating forward. Costs for CO2 emissions of \$8/ton, \$20/ton, \$40/ton, and \$53/ton CO2 cost (in 2010\$)
- **Resource Restrictions**
 - All new resources constructed must be renewable;
 - Retirement of one of the Existing San Juan Coal Facilities which represents retirement of 240 MW of Coal in 2018;
 - Disallowing construction of new nuclear facilities;
 - Requiring any new coal facility to have carbon sequestration capability;”

PNM uses Ventyx’s Strategist model to perform the quantitative and risk analysis of the scenarios listed above.

Qualitative analysis included consideration of factors like reliability, energy efficiency, governmental and regulatory uncertainty.

Stochastic analysis was performed to determine sensitivities to: Load forecast, energy efficiency levels, CO2 price, fuel cost, early retirement of generation facilities due to environmental regulation and RPS compliance.

B-9.12 PORTFOLIO SELECTION CRITERIA

PNM’s selection criteria include: reasonable cost, reliable, energy efficiency compliant, environmental sensitivity, RPS compliant, fuel diversity, flexibility. PNM provides a comparison of the results of its sensitivity analysis. Least cost, lowest carbon and highest reliability appear to be the primary criteria in selecting a particular portfolio.

PNM states that the scenario results provide a strategic outline for how PNM should alter its portfolio selections and resource plan going-forward based on certain changes in market and system conditions.

B-9.13 PROCESS

PNM has an open stakeholder process. Stakeholder input is utilized in every part of the resource planning process. PNM has held 16 stakeholder meetings in the process of developing its IRP.

IRPs are due every 3 years. The utility's resource plan is either accepted or rejected by the Commission. If accepted, the plan becomes the basis for specific approval of new resources and PNM will make a specific request for approval of the required resources.

B-9.14 SOFTWARE

PNM uses PROMOD and Strategist (by Ventyx) for assessing its resource plan alternatives. Strategist "is widely used in the electric industry in the development of resource plans. This comprehensive resource planning tool allows the user to evaluate combinations of various types of resource options and compile a set of up to 5,000 unique 20-year resource portfolios ranked according to total system cost. Strategist's® proprietary dynamic programming algorithm allows the user to optimally select and rank alternative resource plans based on various user criteria, such as minimizing utility cost, which was used in developing PNM's E-IRP. Strategist® is capable of modeling a wide range of resource alternatives such as energy efficiency and demand side alternatives, storage technologies, renewable and conventional generating units, various types of power purchase and sales, and transmission enhancement projects, among others. Strategist® dynamically evaluates all possible combinations of resource alternatives within user specified constraints. Strategist® can perform its resource optimization while maintaining any of these user-defined constraints such as reserve margin, loss of load hours, emergency energy, and emissions."

B-9.15 PROPRIETARY DATA

PNM includes its fuel forecast, demand forecast, and loads and resource table in its publicly available draft IRP. Market price forecasts for purchased power are kept confidential.

B-10 Georgia Power Company (GPC)**B-10.1 LOAD FORECASTING**

Georgia Power Company's load forecasting process uses a combination of end-use and econometric analyses. The forecast is based on projections of economic growth, migration into the state, appliance efficiencies, competing fuel costs, and a variety of other projections. The principal sources of these projections are economic forecasting services, customer surveys, and computer models used by the Company.

B-10.2 NEEDS DETERMINATION

GPC determines its needs over a 20-year planning period by starting with the demand forecast plus reserve margin less existing resources, including reductions for planned retirements, less cost-effective DSM. GPC concluded that its system should maintain a 15 percent system planning reserve margin target 3 years out and inside the 3 year window should maintain a 13.5 percent minimum system planning reserve margin.

At GPC, needs determination also includes transmission needs. GPC has established transmission planning principles for developing its transmission plan. These principles include: transmission planning in compliance with standards and guidelines; minimizing cost associated with transmission expansion, identifying projects with sufficient lead-time to provide for the timely construction of new transmission facilities, developing projects with recognition of the financial capabilities of GPC, coordinating transmission plans with distribution planning and other departments, maintaining adequate interconnections with neighboring utilities; and communicating with

management in such a way that there is a proper awareness of the importance of adequate transmission improvements and system expansion.

B-10.3 TIME PERIOD OF ANALYSIS

GPC uses a 20-year planning period for supply and a 10-year planning period for Transmission.

B-10.4 FUEL PRICE FORECASTING

Projections of natural gas prices were developed by Southern Company Services Fuel Services. The method is not detailed in the IRP. Oil price projections were developed by SCS Forecasting using the 2006 Annual Energy Outlook from the Department of Energy.

B-10.5 RESOURCE COST DEVELOPMENT METHODOLOGY

GPC's Supply-Side Technology Panel meets to discuss various mature and emerging generating technologies available to meet customer needs. Typically, more than 40 technology types are subject to preliminary economic and environmental screening evaluation. Busbar screening models, which compare total capital and operating costs of different type units across a range of capacity factors, are used to compare the relative economies of the various technologies. In addition, under Commission rules, GPC is required to issue an RFP for each new block of supply-side resources identified in the IRP. RFP results are compared to cost-estimates for self-built options.

B-10.6 TREATMENT OF ENERGY EFFICIENCY

Those demand-side programs deemed economically feasible are integrated with the appropriate benchmark supply plan using the PROVIEW™ model. This method brings the demand-side programs into the full cost optimization process where the supply-side options and demand-side programs are evaluated on an equitable basis.

GPC uses end-use models in its forecasting process to capture reduced energy and capacity needs attributed to appliance and other energy efficiency mandates. GPC is required to include a detailed assessment of the maximum achievable cost effective

potential for energy efficiency and demand response programs in its service area. It also completes sophisticated economic and qualitative screening of all of its DSM Programs.

B-10.7 MARKET PRICE RISK ASSESSMENT

Scenario analysis with sensitivities to changes in Load forecast, unit availability, in-service dates of supply and demand side resources, rate impact analysis, availability and cost of purchased power, environment controls (including CO₂ tax), fuel prices, inflation in plant construction costs and costs of capital.

B-10.8 GHG REGULATION RISK

Carbon emissions are modeled in GPC's scenario analysis as a tax.

B-10.9 ENVIRONMENTAL EFFECTS

The Southern Company Environmental Compliance Strategy ("Strategy") addresses recent environmental rulings and requirements (e.g., Clean Air Interstate Rule, Clean Air Mercury Rule, Clean Air Visibility Rule) and reflects the most recent strategy and cost estimates for incorporating these requirements in its IRP process. GPC uses the information in the Strategy for developing sensitivities related to environmental issues, for emission values, and for assessing other environmental factors that affect IRP process. GPC sensitivity analysis addresses sensitivities to emissions including SO₂ and CO₂.

B-10.10 PORTFOLIO DEVELOPMENT

GPC's evaluation process identifies and reviews all conventional and new supply-side generation technologies; performs a preliminary technology screening analysis based on technical, economic, environmental, and resource availability information; performs a more detailed technology screening analysis of the options that passed the preliminary screening, which includes a busbar economic comparison of the candidate technologies; projects the future cost and performance of the selected supply-side alternatives; identifies the technologies to be recommended for inclusion in the resource mix studies and includes detailed analysis of renewable resource technologies.

To develop a supply-side plan, the technologies that passed the detailed screening are further evaluated using the PROVIEW™ computer model to arrive at a benchmark plan. The key input assumptions are generating unit characteristics, fuel costs, reliability needs, financial costs and escalation rates. The optimization process utilizes the full production cost PROVIEW™ model that determines the proper mix of capacity to serve a designated load. The results of this analysis indicate the proposed capacity additions. The capacity additions identified within this analysis serve as a guide for the type of capacity needed in a particular timeframe with the given assumptions.

In the integration step, those demand-side programs deemed economically feasible are integrated with the appropriate benchmark supply plan using the PROVIEW™ model. This method brings the demand-side programs into the full cost optimization process where the supply-side options and demand-side programs are evaluated on an equitable basis.

B-10.11 PORTFOLIO ANALYSIS

Portfolio analysis is completed by Full Production cost Proview. DSM levels are determined using marginal cost and commonly used cost benefit ratios as screening tools.

Portfolio analysis includes the following sensitivities:

- The forecast of load: zero, high and low load growth;
- Unit availability: higher and lower forced outage rates;
- In-service dates of supply and demand resources:
 - Evaluate levels and timing of demand side options;
 - Analyze changes in the timing and availability of various generation technologies;

- Adjust cost and generation mix by setting certain technologies to a breakeven cost in various years of the study.
- Rate impact analysis;
 - Availability and costs of purchased power.
- Environmental controls
 - Study the impacts of a CO2 tax;
 - Evaluate high and low SO2 allowance prices;
 - Evaluate costs on installing full pollution controls on all coal units.
- Fuel prices
 - Adjust gas and oil prices up or down;
 - Evaluate lower coal prices in addition to gas and oil;
 - Study the impact of higher nuclear fuel prices.
- Inflation in plant construction costs and costs of capital
 - Incorporate a higher cost of capital assumption;
 - Evaluate a higher cost of combined cycle generation.

B-10.12 PORTFOLIO SELECTION CRITERIA

GPC's criteria for portfolio selection include:

- Flexibility — Can the IRP be altered if the future is different than expected?
- Long-Term Viability — Will the IRP meet customer needs in the long term?
- Reliability — Does the IRP meet customer needs for reliable service?

- Environmental — Does the IRP consider environmental impacts?
- Risk — Does the IRP represent a reasonable balance between reduced risk and cost?
- Stockholder Value — Will the IRP provide stockholders with the opportunity to earn a fair return on their investment?

B-10.13 PROCESS

Participation by non-utility entities in the selection of supply-side and DSM resources appears to be limited.

B-10.14 SOFTWARE

Production cost Proview; Economic models: uses Economy.com a macroeconomic forecast of the U.S. in various economic models for the State of Georgia. Uses: REEPs, COMMEND, INFORM end-use models; Econometric and regression model, HELM; McFred: Monte-Carlo model for reliability; PROSYM to estimate marginal energy cost; REVREK is a financial model used to convert capital costs into revenue requirements; (PRICEM) is a spreadsheet-based marginal cost model designed to predict change in revenue requirements and other effects attributable to changes in loads and/or revenues; DSM Programs: EnerSim is a comprehensive tool for complex commercial building energy analysis. EZSimRes and Site Pro are two other models used in analysis of DSM programs.

B-10.15 PROPRIETARY DATA

GPC's publicly available IRP documents were redacted. GPC files a document with its IRP that lists what it calls trade secret information. This information includes sensitive details for overall resource planning, such as unit retirement studies, generation analysis and mix data, fuel pricing information, its short-term the load and energy forecast, and its environmental compliance strategy. Long-term loads and resource information in the technical appendix was redacted.

B-11 Seattle City Light (SCL)

B-11.1 LOAD FORECASTING

The load forecast is based on forecasts of several key economic and demographic variables, primarily employment and the number of households in the service area. For each of nine customer sectors, the load forecasting model uses the correlations between load history and the histories of selected economic and demographic variables to project future load. The main drivers for the load forecast are the number of households and the number of employees for several commercial and industrial categories in the service area. For industrial sectors that have only a small number of large firms, adjustments may be made based on relevant information about particular firms.²

B-11.2 NEEDS DETERMINATION

In determining needs, SCL takes into consideration the high range of variability in peak loads during the winter months of November – February. Variability is due mainly to weather; very cold weather can push the one-hour peak load nearly 50 percent higher than average load for the month.

Needs determination for SCL is complicated by the fact that hydro makes up more than 90 percent of generation resources; the system is stressed during periods of drought. SCL models existing resources combined with very low hydro (1 in 20 years) against forecasted electricity demand. Over 1,000 possible combinations of hydropower and load were considered, and each combination was evaluated by month over the 20-year planning horizon.

² SCL's 2008 Draft IRP does not include a discussion of load forecasting methodology. The information discussed in the "Load Forecasting" section herein is taken from the 2006 IRP. We assume the load forecasting methodology did not change from 2006 – 2008. This assumption seems reasonable given that in many other respects the 2006 and 2008 IRPs follow an identical methodology.

SCL plans its resource acquisition such that there is a 95 percent probability that available capacity will be sufficient to meet load. An underlying assumption made is that 100aMW of power could be purchased from the market in times of shortfall. This assumption recognizes the conditions of a “tighter regional market” with “limited availability of energy from the market under critical conditions.”

In developing its needs determination, SCL considered:

- The 1 in 2 (50:50) one-hour peak demand forecast for SCL
- The lowest 5th percentile of hydropower generation
- Assumptions about continuing operation of existing resources (e.g. Boundary relicensing, BPA contract renewal)
- Expiration of existing contracts on schedule
- The need for new renewable resources to meet the requirements of the Washington Energy Independence Act (I-937)

B-11.3 TIME PERIOD OF ANALYSIS

SCL uses a 20-year planning period. A 20-year NPV measure is chosen to evaluate portfolio options.

B-11.4 FUEL AND ELECTRICITY MARKET PRICE FORECASTING

The natural gas prices used in the modeling of the portfolios are taken from Global Energy Decision’s (GED) Fall 2007 baseline forecast.

Electricity price forecasts are calculated in AURORA and are highly correlated with gas price forecasts.

B-11.5 RESOURCE COST DEVELOPMENT METHODOLOGY

The following resource types were considered:

- Hydroelectric Efficiency (Gorge Tunnel)
- Wind Power
- Biomass
- Landfill Gas
- Geothermal
- Natural Gas-Fired Combined-Cycle Combustion Turbines (CCCTs) and Simple-Cycle Combustion Turbines (SCCTs)

In developing resource costs, SCL recognizes that rising commodity prices and a devalued U.S. dollar are driving escalating costs for new resources. However, it also notes that the possibility exists that productive capacity for concrete, steel and wind turbines will increase, causing resources prices to moderate. SCL thus chose not to adjust resource costs upward for what are seen as primarily near term market trends.

Information about the costs of new resources came from many sources, including the U.S. Department of Energy, Northwest Power and Conservation Council, California Energy Commission, and Northwest Utility Integrated Resource Plans. In cases where estimates were inconsistent, a cost that fell within the middle of the range most frequently used.

Transmission costs for new resources are assumed to be consistent with BPA's policy for new transmission. This policy is that the BPA will build new transmission as needed by its customers, not to exceed an amount that would increase rates by 5 percent.

For demand-side resources, SCL utilizes the Conservation Potential Assessment (CPA), conducted by energy analysis firm Quantec, which examined available energy savings in the residential, commercial and industrial sectors in SCL's service area. The assessment considered dozens of conservation measures, with hundreds of

permutations across segments and construction vintages, distinguishing between discretionary and lost opportunity resources. The study also incorporated non-energy benefits.

In its most recent IRP, SCL amends its assumptions regarding the CPA in order to reflect current legislative requirements. In its 2006 IRP, SCL assumed achievable potential was 70 percent of the technical potential in the CPA; in order to comply with Initiative 937 requirements, 2008 IRP revises the percentage for achievable potential assumptions to 85 percent for all discretionary resources (existing buildings and equipment) and 65 percent for all lost opportunity resources (new buildings and equipment). A cost effective threshold of \$60 per MWh (used in the 2006 IRP) was applied to the Conservation Potential Assessment.

SCL also takes distribution cost into account in its treatment of DSM. Since DSM is assumed to defer investment in new distribution infrastructure, the cost of all energy efficiency measures assessed in the IRP was reduced.

B-11.6 TREATMENT OF ENERGY EFFICIENCY

Forecasts do not include any utility-sponsored conservation or DSM. Rather, conservation and DSM is treated identically to a generating resource in the modeling. See the previous section, *Resource Cost Development Methodologies*, for additional detail.

B-11.7 MARKET PRICE RISK ASSESSMENT

To estimate natural gas price risk, GED (now Ventyx), the forecaster on which SCL relied, performed a stochastic analysis of long term Henry Hub gas prices to develop a probability distribution of expected prices. The 75th percentile of this distribution makes up the high gas price scenario used in scenario analysis. However, SCL notes that 2008 natural gas prices have reached the upper end of the distribution forecasted by GED in 2007. The extent to which this new information was taken into consideration is not clear.

B-11.8 GHG REGULATION RISK

For SCL, GHG regulation is less a risk than a reality. City Council Resolution 30144 directs SCL to mitigate greenhouse gas emissions from any fossil fuel use and to set a long-term goal of “net zero” annual greenhouse gas emissions. Executive Order 07-02, includes goals to reduce overall GHG emissions in the state to 1990 levels by 2020, and further thereafter. This order also establishes a GHG emissions limit of 1,100 pounds of CO₂ per MWh of power, roughly equivalent to an existing natural gas plant emission rate.

Furthermore, Washington state’s Initiative 937 requires electric utilities to have 15 percent of their energy provided by new, renewable resources by 2020. Hydro power, which makes up more than 90 percent of SCL’s generation resources, does not count toward I-937’s renewable resource requirements. Thus, SCL is effectively limited in its resource choices to conservation and renewables.

Perhaps because these restrictions severely limit SCL’s non-renewable generation options, SCL is not explicit in describing its method for deriving emissions costs values or analyzing potential risk to those estimates, though it is clear that SCL does include carbon allowance costs and abatement costs for other emissions in its analysis.

B-11.9 ENVIRONMENTAL EFFECTS

SCL’s Environmental Policy Statement calls for it to avoid, minimize or mitigate impacts to the ecosystems that it engages with and to consider environmental costs, risks and impacts when making decisions. SCL’s Vision, Mission, Values Statement reaffirms that minimizing environmental impacts and enhancing, protecting and preserving the environment are key parts of the utility’s goals. Environmental impacts are explicitly taken into account in SCL’s IRP, as this is one of the four criteria used to evaluate the IRP candidate portfolios.

Air emissions were explicitly included in the modeling and analysis of portfolios. For each generating resource portfolio, total emissions of carbon dioxide (CO₂), sulfur dioxide (SO₂), nitrogen oxides (NO_x), mercury (Hg), and particulates (PM) are estimated over the 20-year period. A monetary cost is applied to the emissions to approximate the cost of complying with potential environmental regulations in the future. For carbon emissions, this monetary cost is assumed to be a carbon allowance cost; for all other emissions the cost is assumed to be the cost of emissions control equipment. The compliance costs of each portfolio are tabulated by year and expressed as a net present value.

Biomass and landfill gas were assumed to have zero net impact on greenhouse gas. They were considered closed-loop systems, where the carbon dioxide emissions are equal to the carbon dioxide captured by the plants and other organic matter prior to being combusted.

For other environmental elements including land use, surface and groundwater, soils and geology, plants and animals, employment, aesthetics and recreation, environmental health and cultural resources, each portfolio was assessed for the level of impact in each element.

B-11.10 PORTFOLIO DEVELOPMENT

Washington State's Initiative 937 requires electric utilities to have 15 percent of their energy provided by new, renewable resources by 2020. Hydro power, which makes up more than 90 percent of SCL's generation resources, does not count toward I-937's renewable resource requirements. Thus, SCL is effectively limited in its resource choices to conservation and renewables, though natural gas fired combustion turbines were also considered.

After gathering information on the reasonable range of resources, SCL manually constructed candidate portfolios designed to meet these objectives:

- Minimize the amount of resources needed to meet resource adequacy and I-937 requirements, largely by accelerating the acquisition of conservation.
- Use lower cost resources, such as exchanges and capacity purchases, in the early years to maximize the net present value of the portfolios.
- Avoid large resource commitments in the early years by using exchanges, capacity purchases and conservation.
- Produce portfolios that will meet the resource adequacy requirement and I-937 requirements.
- Use scalable resources when possible as opposed to separate projects (e.g. wind, geothermal, combustion turbines).
- Ensure that there is sufficient new generation in summer months to meet proposed seasonal exchanges.
- Avoid exchanges or resources in the early years that would require new transmission to be constructed on an unreasonably short timeline.

B-11.11 PORTFOLIO ANALYSIS

Portfolios were evaluated against 4 criteria:

- provide reliable service
- minimize cost to customers
- manage risks
- minimize environmental impacts.

AURORAxmp is used to perform the calculations that help illuminate quantitative measures related to the criteria above. A set of quantitative measures was devised that

allowed comparison across the criteria. These were: net power cost; risk of higher cost (5 percent probability worst outcome when sensitivity testing for hydro output, fuel cost, and electricity demand); and direct emissions costs. Portfolios were measured and ranked across these measures.

Analysis was performed on a first round of six portfolios, each of which was compared to a portfolio made up of SCL's existing resources plus spot market purchases only. Based on results, a second set of portfolios was constructed for a second round of analysis. For example, fossil fuel generation sources were eliminated from consideration in the second round because of the high assumed cost of emissions allowances. Scenarios were used to further test and analyze the Round 2 portfolios.

Since the prior IRP, SCL changed its scenario analysis approach. The 2006 IRP scenarios represented different paths that the national economy and electrical energy industry might take. Each scenario had varying effects on natural gas prices, renewable resource prices, non-renewable resource prices, carbon tax, etc.

For the 2008 IRP, the scenarios focus on specific issues stakeholders and policymakers raised. They address these "what if" questions :

- What if the region experiences unprecedented growth throughout the planning period?
- What if the service area experiences a recession in the near-term years, pushing out the need for resource additions?
- What if climate change proceeds as projected by regional researchers?
- What if plug-in hybrid vehicles become commercially available?
- What if natural gas prices follow a high case rather than the base case forecast?
- What if the cost of renewable resources is much higher than expected?

B-11.12 PORTFOLIO SELECTION CRITERIA

The preferred portfolio was the one that SCL found to perform the best against the criteria discussed in the Portfolio Analysis section above. It was the “best performing in risk measures, a close second best in net power cost, and, like the other Round 2 portfolios, has low direct emissions costs.”

B-11.13 PROCESS

The two-year planning process that culminated in SCL’s preferred portfolio included these steps:

- Public Involvement of citizens and stakeholders with diverse perspectives.
- Recruiting expertise from inside and from outside the utility.
- Licensing and installing a sophisticated computer model, the AURORAxmp® Electric Market Model, for power planning.
- Calibrating the model for the characteristics of SCL’s complex hydroelectric operations and purchase power contracts.
- Thoroughly assessing conservation resource potential in the service area.
- Forecasting customer demand for power each month through 2027.
- Developing a resource adequacy measure, crucial for defining the timing and amount of future need.
- Developing costs and characteristics of alternative resources to be included in the candidate resource portfolios.
- Constructing and modeling Round 1 candidate resource portfolios for evaluation against four criteria: Reliability, cost, risk and environmental impacts.

- Constructing and modeling Round 2 candidate resource portfolios, based on findings and comments in response to Round 1.
- Updating an Environmental Impact Statement (EIS) for new resource portfolios.
- Recommending a resource strategy and near-term resource action plan.

The IRP stakeholder committee represents residential, commercial and industrial customers, environmental organizations, power resource developers and energy related government agencies. This committee guided resource planning efforts during five meetings with comments, questions and suggestions throughout the process. Members of the public also attended IRP public meetings and offered suggestions that helped to shape the analyses used in the planning process.

B-11.14 SOFTWARE

SCL uses AURORA_{xmp} for analysis. AURORA forecasts future energy prices, given the structure and characteristics of the past and current market; evaluates the economic performance and reliability of a resource or a portfolio of resources based on cost minimization; and performs risk analysis and tests the reliability of resources under a number of scenarios. The model uses economic dispatch logic to select which resources operate, considering electricity demand, generation and transmission costs, and seasonal hydroelectric generation patterns. The model also has the capability of locational marginal pricing (LMP) market analysis. While the Pacific Northwest does not have an LMP market, the California ISO operates a power market that has been designed using locational marginal pricing principles.

B-11.15 PROPRIETARY DATA

None discussed.

B-12 Xcel Minnesota / Northern States Power (NSP)

B-12.1 LOAD FORECASTING

Forecasts for residential customers are derived from population and household projections provided by Global Insight, Inc. Econometric modeling is performed to create the forecast, with population projections being a key variable for the residential sector. NSP has found that over 99 percent of variation in residential energy use can be explained by population size and weather.

For commercial and industrial use, econometric modeling considers gross state product, employment, real personal income and productivity. Global Insight, Inc. provides the economic forecasts used in the models.

For the remaining customer classes – Public Street and Highway Lighting, Other Sales to Public Authorities, Interdepartmental and Firm Wholesale Sales – NSP uses trend analysis and customer specific data.

The median forecasts for peak demand and energy are created to have a 50 percent probability that actual usage will be higher and 50 percent probability that it will be lower. From the median forecast, a range is created such that there is a 90 percent confidence level that the actual usage will fall within the range. The confidence interval is determined through Monte Carlo analysis taking 10,000 random draws of the weather distribution and the Minnesota Gross State Product distribution.

In order to be reasonably assured of meeting capacity in extreme weather conditions, NSP uses the 90 percent peak demand forecast for planning purposes. The 50/50 median forecast is used for energy.

B-12.2 NEEDS DETERMINATION

NSP compares the forecast described above to owned generation, long-term contracts, and projected short-term purchases, to arrive at a needs determination. NSP also

considers proposals under review, planned additions to meet RPS standards, and assumes that a particular plant will be successfully relicensed. NSP acknowledges that if any of the planned resources, or DSM, fail to materialize, additional resources will be required, and that therefore agreement on a hedging plan is necessary.

Using the 90 percent probability peak demand forecast is intended to allow NSP to meet the 15 percent reserve margin required in the MAPP Reserve Sharing Group.

Xcel Energy became a member of the Midwest Planning Reserve Sharing Group (PRSG) in May 2007, which has been formed by utilities seeking to create a uniform planning reserve margin for the entire Midwest. NSP will likely withdraw from MAPP as a result and use the Midwest PRSG guidelines for reserve. The Midwest PRSG is conducting loss of load expectation (LOLE) studies to determine the reserve margin that would allow each utility to maintain a reliability level of no more than one day's interruption of service in ten years. This analysis will have a slightly different basis from the MAPP reserve requirements:

- the reserve requirement would be based on NSP's 50 percent forecast of uninterrupted load, rather than actual peak load measured after the fact, and
- the requirement would be based on maximum dependable capability (MDC) instead of Uniform Rating of Generating Equipment (URGE). For many Xcel Energy units the URGE rating, which estimates the theoretical maximum of units, is considerably higher than the units' MDC.

Early indications are that the reserve margin resulting from this study will be lower than the 15 percent reserve margin currently required.

B-12.3 TIME PERIOD OF ANALYSIS

NSP uses a 15-year planning period. However, a 40-year period is used for modeling, allowing all costs and benefits for resources added early in the plan to be taken into account.

B-12.4 FUEL AND ELECTRICITY MARKET PRICE FORECASTING

NSP develops a natural gas price forecast for the period 2008 through 2012 directly from the reference day's closing prices for the NYMEX Natural Gas forward contracts.

Beginning in January 2013, NSP uses the simple average of the most recent estimates from various sources, including the U.S. Energy Information Administration's Annual Energy Outlook, PIRA Energy Group, Cambridge Energy Research Associates, and Global Insight, Inc.

B-12.5 RESOURCE COST DEVELOPMENT METHODOLOGY

Resource costs for pre-determined additions are based on known costs. For other additions, costs are generated by the Strategist expansion planning model.

NSP estimated the amount of short-term resources it could be confident would be available on the market, and assumes this amount of short-term purchases will be used to help meet peak demand. NSP plans to use non-short-term market mechanisms to meet the remaining need for peak demand.

NSP assumes the Production Tax Credit (PTC) for wind generation will continue through 2015, a key factor when such a large portion of planned generation is made up of wind.

Transmission upgrades are based on a five-year forecast of capital expenditures and capture the average growth over that period with subsequent years increased for inflation.

B-12.6 TREATMENT OF ENERGY EFFICIENCY

In past forecasts, embedded DSM from past programs was included in the forecast, but the forecast did not incorporate estimated savings from future DSM programs. Future DSM savings were made as an adjustment during modeling. In determining the forecasts in this Resource Plan, NSP made adjustments to the forecasts to account for future DSM savings, and no longer makes adjustments during modeling. The level of

DSM is set to equal the 1.1 percent target in 2007 legislation. The monthly conservation impacts are calculated by customer class, and then subtracted from the customer class level sales forecasts that result from the regression modeling process. This has the effect of lowering the forecasts for peak demand and energy.

B-12.7 MARKET PRICE RISK ASSESSMENT

NSP tests sensitivity to fuel price risk through scenario analysis, wherein natural gas, coal, and nuclear fuel prices are independently adjusted upward and downward by 20 percent.

To reflect the potential impact of periods of high seasonal natural gas volatility, NSP created a sensitivity analysis that incorporates the cost of natural gas hedging tools and natural gas storage into the natural gas price forecast.

B-12.8 GHG REGULATION RISK

To develop CO₂ emissions price scenarios, NSP researched recent, publicly available analyses of mandatory greenhouse gas policies.

NSP assumes a base case \$20/ton charge for CO₂ starting in 2010 and escalating at 2.5 percent per year. Uncertainty around this variable is addressed through scenario analysis, including scenarios showing a \$9/ton value and a \$40/ton scenario.

B-12.9 ENVIRONMENTAL EFFECTS

NSP includes environmental externality costs as required by Commission order. Where certain emissions are expected, due to legislation, to have direct economic consequences, these costs are estimated according to anticipated regulatory or market costs. NSP assumes a cap and trade permit systems for SO₂, NO_x, and Mercury, consistent with the U.S. EPA Clean Air Interstate Rule.

In addition, NSP provides a review of plant-by-plant emissions, with plans to decommission certain plants in order to improve the company's overall emissions profile.

B-12.10 PORTFOLIO DEVELOPMENT

Portfolio development is largely driven by recent legislation and regulation concerning renewable energy standards, DSM goals, and limits on greenhouse gas emissions. For example, coal is considered only inasmuch as it includes carbon capture and storage. More significantly, the renewable energy standard requirement to meet 25 percent of load through wind energy by 2020 significantly constrains the options open to meet load growth. Subject to these significant constraints, NPS uses the Strategist planning model to develop the resource mix.

Strategist uses generically defined resources to meet future demand when existing resources fall short. The Company used the following generic resources as model inputs for this Resource Plan:

- 160 MW gas-fired Combustion Turbine peaking unit (CT)
- 600 MW gas-fired Combined Cycle intermediate unit (CC)
- 500 MW Super Critical Pulverized Coal base load unit with partial carbon sequestration (SCPCwSEQ)
- 100 MW Wind project (However, because of uncertainty regarding the effect of the required (through the renewable energy standard) 25 percent wind on the system, NSP does not allow wind to exceed the 25 percent level)
- The CTs become available for inclusion in the expansion plan starting in 2012, CCs 2013, SCPC 2015, and Wind 2009. Cost and performance data for these units are based on a consultant's estimates and internal company data.

B-12.11 PORTFOLIO ANALYSIS

NSP creates a Reference case based on median energy, 90 percent confidence interval peak demand, and various assumptions regarding planned expansions and resources required to meet legislative goals. Specifically, the Reference case does not include expansion of existing nuclear plants or continuation of a hydro contract. The Reference case is then altered through scenario analysis – wherein the scenarios test for nuclear expansion and hydro contract extension among other factors – and tested for sensitivity to changes in key variables.

Each contingency around planned upgrades and planned purchases was added separately to the reference case in the year that the resource is proposed. Strategist then calculated a least-cost expansion plan for each alternative. Finally, each expansion plan was evaluated using scenario analysis.

B-12.12 PORTFOLIO SELECTION CRITERIA

To select the preferred portfolio, NSP compares the Present Value Revenue Requirement (PVR) of the Reference case to alternative cases created to test various options such as the expansion of existing nuclear plants and the continuation of hydro contracts. NSP selects a portfolio that includes many of the resource expansion options tested, such as expansion of nuclear and continuation of hydro. It was found that PVR was lower under this preferred plan than under the Reference case, and that these benefits held well under sensitivity testing through scenario analysis.

In essence, NSP used Strategist to compare a generic expansion plan developed by Strategist to expansion and continuation of existing and planned resources already controlled by NSP, and found that expanding existing plants and continuing with planned resources would be cheaper than any generic alternatives modeled through Strategist.

B-12.13 PROCESS

The plan takes significant direction from the Minnesota legislature, which has recently enacted laws requiring: a renewable energy standard; annual energy conservation goals; and GHG reduction goals. As a result of these laws, NSP may not build, import, or enter into a long-term contract for any power that would increase GHGs on a statewide basis, and must use a carbon value of \$4 - \$30 in its analysis.

B-12.14 SOFTWARE

Strategist resource planning software.

NSP notes the following limitations of Strategist. Although it uses hourly information, it is not a chronological model. Hourly patterns for energy demand are rearranged into load duration curves and thermal dispatch simulations are based on these curves. This allows NSP to quickly simulate several years of operation on its system, but the model loses the ability to capture some operational detail, such as the ramp rates on our generating units. This makes it difficult for NSP to use the model to evaluate the benefits of quick start combustion turbines.

B-12.15 PROPRIETARY DATA

None discussed.

B-13 British Columbia Hydro (BCH)

BC Hydro is one of North America's leading providers of clean, renewable energy, and, with approximately 4,500 employees and net income of \$400 million in 2007, the largest electric utility in British Columbia, serving approximately 95 percent of the province's population and 1.7 million customers. BC Hydro generates between 43,000 and 54,000 GWh of electricity annually, depending on prevailing water levels.

BC Hydro's Electric Generation System extends throughout various regions of the province. The 30 integrated hydroelectric generating stations, two gas-fired thermal power plants (47 MW & 950 MW both natural gas) and one 46 MW natural gas combustion turbine station (with Diesel backup) have a total installed generating capacity of over 11,000 megawatts (MW). Power Smart conservation programs deliver cumulative annual incremental energy savings of 2,518 GWh.

As a provincial Crown corporation, BC Hydro reports to the Minister of Energy and Mines, and is regulated by the British Columbia Utilities Commission (BCUC).

B-13.1 LOAD FORECASTING

BC Hydro's load forecast uses a bottom up methodology. Residential sales forecasts are weather normalized and consider use reduction and housing starts. The commercial forecast reflects the performance of the BC economy, and the industrial forecast considers factors such as: economic conditions in the US, China and Japan; events that effect commodity price; appreciation in the Canadian dollar; U.S. housing starts; pulp and paper demand; and beetle infestation. BC Hydro utilized consultant information (AMEC's report on BC's forestry sector) in the industrial load forecasts.

BC Hydro uses a Monte Carlo simulation to estimate load forecast uncertainty within +/- 10 percent confidence bands. Key variables tested include economic activity, weather, electricity rates and price elasticity. BCH concludes that the forecast ranges as produced by the Monte Carlo analysis are a reasonable representation of the range of expected variability around the Forecast.

BC Hydro's 2008 load forecast did not include potential load increases from PHEV. It does include verifiable industrial customer attrition such as the closer of one large industrial copper customer based on public domain information.

BC Hydro determines a 10-year rolling average of degree days to be the best representation of weather for forecasting energy sales. In addition, a rolling 30-year

period of the coldest daily average temperature is deemed an appropriate method for forecasting peak demand.

Incremental load savings due to changes in rate structure (conservation rates) are modeled as part of BCH's overall DSM and included in the load forecast.

B-13.2 NEEDS DETERMINATION

The Company's needs are derived from the demand forecast (including losses) plus reserve margin ("N-1") less existing company owned or controlled resources using an energy balance and capacity balance. In the near-term, need is balanced by DSM programs. Currently planned generation capacity expansion is also considered.

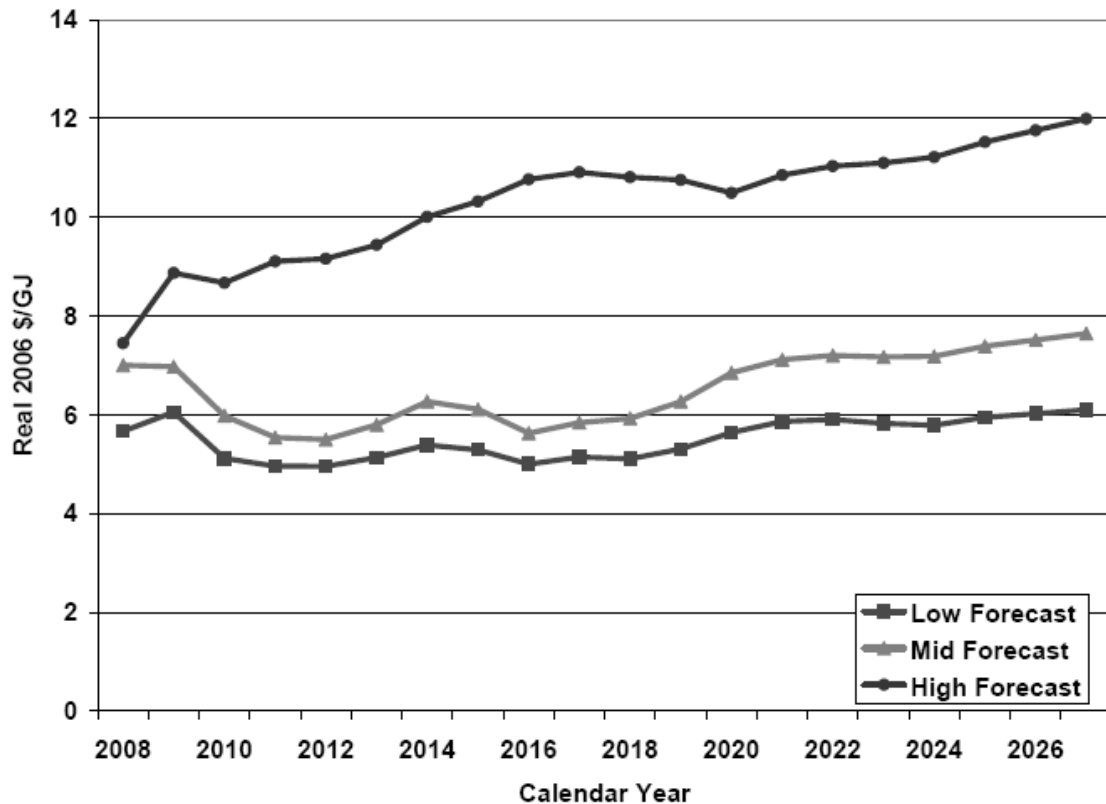
B-13.3 TIME PERIOD OF ANALYSIS

20-year planning period.

B-13.4 FUEL AND ELECTRICITY MARKET PRICE FORECASTING

BC Hydro retained Global Energy Decisions (GED) for fundamental research and natural gas price forecasts. Three gas price forecasts (based on prior work GED had completed for the CEC) were chosen as representing a reasonable range for a Base, Low, and High forecast. However, because the forecasts were at least a year old, there was a need to weight them given market conditions that had developed since the forecasts were created. It was found that current prices were somewhat above the Base case, but still below the High case. To account for the new circumstances, BCH asked GED to assign probabilities to each forecast, which GED did, using the Modified Delphi Method, a methodology that systematically assists experts in reaching consensus. GED assigned the following probabilities to each forecast, which BCH was then able to use for weighting in its analysis: Base (44 percent), Low (3 percent), and High (53 percent).

Figure 4-2 Natural Gas Price Scenarios at Sumas Hub by Calendar Year



Electricity prices are modeled under a computer simulation of the hourly supply-demand balance for the WECC regional market, which include the Western U.S. states, B.C. and Alberta. The dispatch cost of the marginal resource at the point where supply and demand are in equilibrium determines the market price for that hour. Monthly and yearly average prices are obtained by aggregating the computed hourly prices. The electricity and gas prices are calculated for the next 20 years.

Electricity price forecasts use GHG and renewable energy assumptions for the western region of Canada and the U.S. following existing and anticipated renewable and GHG legislation within the WECC.

B-13.5 RESOURCE COST DEVELOPMENT METHODOLOGY

Supply side options must conform to BC government policy which may rule out a particular technology or form of energy. The IRP notes that current policy restrictions specify that options must be located within BC and be greater than 50kW.

For supply costs, the IRP relies in part on a separate document, the Resource Options Update (ROU) which updates supply side resource option data by examining technology characteristics (including potential availability), costs, project lead times, project life, and environmental and social information.

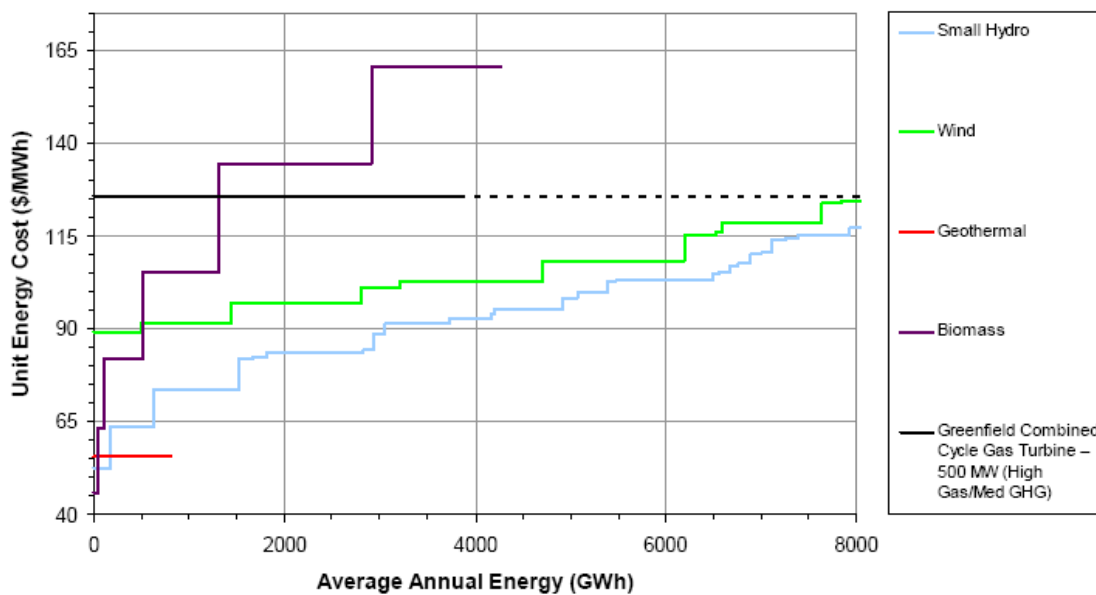
BCH considered resources available and made cost estimates based on specific studies or local cost knowledge. Resources considered include:

- DSM
- Small-hydro – uses a GIS software-tool to evaluate potential. Supply curve: Potential/dependable capacity = 1.98/0.068 GW with 6,800kWh ranging between \$50 & \$110/MWh
- Biomass – Woodwaste, MSW, landfill biogas. Supply curve: potential/dependable capacity = 534MW; firm energy: 4,267GWh/yr with prices ranging between \$44 and \$148/MWh.
- Wind – Capacity factors ranging between 21 & 40 percent; Potential capacity = 5,200 MW, supply curve: 0-10,000GWh, \$90-\$145/MWh. Costs include incremental firm transmission, line losses, a capacity credit and integration costs.
- Geothermal - Cost and resource potential was updated by reviewing the current activities of the South Meager Geothermal project with the permit holder, Western GeoPower Corp. GeothermEx Inc., an independent consultant, concluded the South Meager Geothermal project has the potential to support up to a 100 MW plant. Also, publications, such as the “Green Energy Study for BC”,

by BC Hydro Engineering (2002), “Electrical Potential in Northwest BC” by BCTC (2007) and “Potential improvements to Existing Geothermal Facilities in California” by Geothermal Research Council (2006) were reviewed.

- Coal (with CCS) - Powertech was hired to assess future zero emission coal power potential. Too much uncertainty was concluded and thus coal technologies are excluded from the LTAP.
- NG fired generation – AMEC was engaged to update the planning-level cost and technical data for the various SCGT and CCGT projects identified in the 2005 ROR. Based on information provided by AMEC, the resources options data sheet(s) for each project was updated. The approach taken by AMEC on capital costs was to develop factored cost estimates for key project components, and then update each component to current price levels using relevant escalation indices. AMEC specifically obtained updated vendor budgetary quotes (e.g., from General Electric) for the cost of the various gas turbine generator packages which are a key component of each of these projects. Potential capacity = 4,600 MW, supply curve: 0-35,500GWh, \$60-\$147/MWh.
- Large hydro –new dams and repowering existing dams are considered.
- Pumped storage – Potential capacity = 1,500 MW, supply curve: N/A GWh,

**Figure 3-10 Supply Curve Summary
Adjusted UECs**



B-13.6 MARKET PRICE RISK ASSESSMENT

BC Hydro uses a “risk framework” which takes the following steps:

- Depict stochastic uncertainties through quantitative analysis - For quantifiable uncertainties for particular variables, parameters can be numerically generated to produce a known statistical process that represents their variability from their historic values using a Monte Carlo analysis. Key stochastic uncertainties and related risks include:
 - Load growth
 - BC Hydro’s existing system & operations, including inflow and water variability and the risk of insufficient energy
 - NG and electricity spot market prices

- Scenario Analysis - develop a range of discrete outcomes which de-emphasize single point estimates for uncertain parameters and, instead, develop ranges of possible outcomes. For some elements, this meant developing distinct scenarios that covered off upper and lower bounds and a mid-case. Scenario Analysis is used to evaluate scenario uncertainties that are also parameter driven but where the parameter variability cannot be reasonably represented by a known statistical process. Instead, a fundamental change or structural shift is made to the expected value of some parameter. In the case of changing scenario uncertainties, the time evolution of critical inputs, e.g., natural gas and electricity prices, takes a distinctly different path rather than fluctuating around an expected value.
- Qualitative Assessment – A number of uncertainties, for example the uncertainty of permitting a rebuilding of Burrard, do not lend themselves to either stochastic or scenario analysis. For these uncertainties, BC Hydro has either retained experts to provide advice or relied upon professional judgment. Key uncertainties and related risks that were assessed on a subjective basis include:
 - Current and future regulatory and public policy developments, such as GHG regulation, new air emission standards and related mitigation cost risks, IPP development including type of resource and location, and the risk that the type and location of resources require significant capacity and transmission support;
 - IPP attrition rates from Calls;
 - DSM deliverability and risk that the response to DSM is less than planned or required;
 - Transmission supply and the risk that this long lead time resource faces construction delays and permitting problems; and

- Burrard (an existing thermal gen plant) and the uncertainty around its technical ability and social license to deliver firm energy and capacity.
- Attach Probability Estimate to Discrete Outcomes. For the key risks that had their uncertainty captured through stochastic modeling (including: Load Forecast, DSM Savings, and IPP attrition), the information contained in their continuous uncertainty distributions were used to put probabilities on the three discrete levels of outcomes.
- Build a probability tree - This probability tree for the 2008 LTAP provided the key backdrop against which resource planning options and portfolios were compared. By providing a few discrete branches in this probability tree, this framework allowed specific portfolios to be created for each future scenario. For the questions of interest, analyses were carried out across all of these scenarios with the costs and relative likelihood of these being reported.

B-13.7 GHG REGULATION RISK

BC Hydro's GHG price forecast considers two key drivers influencing GHG price, the stringency of regulatory policy (targets) and the flexibility of compliance mechanisms (supply/availability). Three scenarios were created by Natsource (consultant) to describe the range of potential GHG policies for the years 2007-2050, and probability distributions were assigned. The most probable case (60 percent) is a linked market scenario in which Canada and the US establish ambitious targets and trading by 2015, and link with international framework by 2020. Prices range from CND \$14 (now) - \$300/tonne GHG (2020)

B-13.8 ENVIRONMENTAL EFFECTS

U.S. RPS legislation and an estimation of the market affects of trading renewable energy into the U.S. is considered.

B-13.9 PORTFOLIO DEVELOPMENT

Portfolios are developed using a stakeholder process with the goal of reaching predefined criteria. BC Hydro assumes that the majority of incremental resource additions will be acquired through competitive processes where the outcome cannot be predetermined. As such, BC Hydro makes an assessment of which types and quantities of different resources are likely to emerge from these competitive processes. Supply curves and project-specific information (detailed in the “Resource Cost Development Section” above) for the different resource types are used to develop different resource portfolios.

B-13.10 PORTFOLIO ANALYSIS

A portfolio trade-off analysis is used to test portfolios against 5 key questions: resource mix, DSM, a particular site development (called Site C), maintain, replace, or repower a thermal gen station, supply security (wholesale spot market purchases).

B-13.11 PORTFOLIO SELECTION CRITERIA

Portfolios include the timing and volume of resource additions using a trade-off analysis considering key risks such as market risks, GHG emission risks, provincial and federal energy regulatory developments, environmental and social development risks, stakeholder interests, and DSM uncertainties.

Portfolios are selected based upon the following criteria: Maximize reliability, Minimize financial cost, and minimize environmental risk. Portfolios do not appear to be ranked. Instead, the actual decision to buy or build a particular resource is made during the competitive acquisition process or other regulatory and approval processes.

B-13.12 PROCESS

First Nations (a term of ethnicity that refers to the Aboriginal peoples in Canada who are neither Inuit nor Métis people) and other stakeholder input into the portfolio construction process came from Provincial Integrated Electricity Plan Committee

(PIEPC) members. PIEPC identified the objectives of individual portfolios and worked through the portfolio development process with BC Hydro. PIEPC provided recommendations on portfolios to be constructed to address each of the five key questions. PIEPC members' input was used to form some of the key inputs and assumptions that were used and tested in the portfolio evaluation process

B-13.13 SOFTWARE

BC Hydro's portfolio modeling process employs two internally developed models:

- Multi-Attribute Portfolio Analysis (MAPA); and,
- Hydrological system simulation model (HYSIM).

MAPA is a spreadsheet-based model, which performs most of the portfolio evaluation steps, including discounted cash flow (economic) analysis and the tracking of portfolio attributes. MAPA gathers costs and attributes details of each project from a database that contains data for all of the resource options. The variable cost component is derived from BC Hydro's HYSIM model. MAPA then generates a summary of the annual and 20- year performance of each portfolio over the planning period for all of the attributes.

B-13.14 PROPRIETARY DATA

None discussed.

B-14 Pacific Gas & Electric (PG&E)

B-14.1 LOAD FORECASTING

PG&E developed three load growth scenarios, all of which begin with the PG&E load forecast for 2007 approved by the CEC. For years beyond 2007, PG&E uses CEC projections from the 2005 Integrated Energy Policy Report. The CEC low forecast is used for PG&E's low forecast, the CEC high forecast is used for PG&E's expected, or base, forecast, and for PG&E's high forecast, PG&E uses a growth rate 0.3 percent higher than the CEC's high forecast. This high growth rate forecast is intended to represent a

period of rapid growth such as was observed during the dot-com/telecom expansion of 1995-2000.

B-14.2 NEEDS DETERMINATION

PG&E needs determination includes the following elements:

- peak-demand based on the load forecasts described above
- a consideration of planned facility retirements
- demand-side and supply-side resource additions that are developed and available to meet the annual peak demand
- a 15 percent to 17 percent planning reserve margin (“PRM”) on a 1-in-2 peak demand load forecast

PG&E calculates needs on both a 1-in-2 summer temperature demand with 15 percent planning reserve margin, and a 1-in-10 summer temperature demand with 16 percent planning reserve margin, and finds that resource needs grow from 1,700 MW by 2016 in the first case to 2,900 MW by 2016 in the second case.

Loss of Load Probability (LOLP) and Loss of Load Expectation (LOLE) are addressed in the scenario analysis of the candidate portfolios.

B-14.3 FUEL PRICE FORECASTING

For natural gas, NYMEX forward prices, with a location adjustment, are used for the first 5 years (through 2011). From 2011-2015, electricity forward prices are used to estimate gas prices, with the ratio being determined by the observed ratio in the final 12 months of gas forwards. Thereafter, the gas forecast adopted in the 2005 MPR process is adopted.

For electric market prices, forward quotes are used through 2015. For 2016 and beyond, electricity prices are based on the MPR gas price forecast.

B-14.4 RESOURCE COST DEVELOPMENT

PG&E developed resource cost estimates based on an assessment of resource availability, past experience, and RFO responses.

Transactions and solicitations are reviewed with a Procurement Review Group (PRG). The Commission directed PG&E to consult with the PRG for specific types of transactions including: (1) overall interim procurement strategy; (2) proposed procurement contracts before the contracts are submitted to the Commission for expedited review; and (3) proposed procurement processes including but not limited to RFOs which result in contracts being entered into in compliance with the terms of the RFO.

B-14.5 TREATMENT OF ENERGY EFFICIENCY

In valuing demand-side alternatives, PG&E uses the Commission's Standard Practice Manual's total resource cost ("TRC") test. Under the TRC test, the costs that PG&E and its customers are expected to incur in implementing an alternative resource are compared to the expected benefits that would be obtained from that alternative resource. Those benefits include the energy and/or capacity costs that would be avoided by utilizing that alternative resource. As long as PG&E's avoided energy and capacity costs are based on market prices, then PG&E's evaluations of supply-side resources and demand-side resources are consistent, and make it possible to compare supply-side resources to demand-side resources.

B-14.6 MARKET PRICE RISK ASSESSMENT

Risk associated with fundamental shifts in the marketplace is covered through scenario analysis; stochastic risk is analyzed using Monte Carlo simulations of power and gas prices. Both approaches rely on volatilities of electric and gas, correlations between them, and Monte Carlo simulation.

The scenarios are developed using the results of 3,000 Monte Carlo simulations of the correlated on- and off-peak electricity and gas prices at a monthly level using simulation paths that exhibit sustained high prices and sustained low prices.

Variability *within* a given scenario is estimated by a daily Monte Carlo simulation, using daily volatilities and correlations between electric and gas prices. The volatilities and correlations for these simulations are obtained from broker provided and historical data. The 95th percentile price is reported. This metric is further described in the passage below:

The To-expiration-Value-at-Risk (“TeVaR”) metric is a measure of unexpected changes in PG&E’s electric portfolio costs. TeVaR measures how high the net generation cost to PG&E customers for the period may become if certain market changes occur.

The TeVaR metric is computed using a Monte Carlo simulation. For each “trial,” daily spot prices are randomly generated for each day, and hydro conditions and electric load are simulated for each month. The prices used in the simulation are consistent with current market forward prices, volatility term-structures implied by market data, and with historical correlations of market data. For each day of the projection period, the net cost is computed for every position in the portfolio. The daily and monthly net costs are accumulated over the portfolio and over the projection period to produce a single (aggregated) net cost for each such trial. The variation of net costs over trials produces a probability distribution of net costs. Costs are represented as negative numbers, so the 1st percentile in the distribution of net cost represents more cost to customers than the 10th percentile in the same distribution of net cost. The difference between the mean net cost and the 5th percentile of net cost is identified as TeVaR at the 95th percentile, or “TeVaR95.” (p.169)

PG&E reports its electric portfolio TeVaR to the Commission's Energy Division on a monthly basis. In addition, D.03-12-062 requires PG&E to notify and meet and confer with the PRG if between quarterly PRG consultations, PG&E's estimated portfolio risk exceeds 125 percent of the Customer Risk Tolerance level which the Commission set at a one cent per kWh impact to retail rates.

In July 2005, PG&E formally expanded its price risk management process specifically for the gas component (*e.g.*, electric fuels) of the electric portfolio by implementing a gas hedging program.

B-14.7 GHG REGULATION RISK

Pursuant to Commission order, a GHG adder is included in Long-Term Request for Offer (LTRFO) bids (\$8/ton in 2004, escalating at 5 percent per year).

B-14.8 ENVIRONMENTAL ATTRIBUTES

PG&E considers GHG emissions and environmental stewardship in its resource planning and evaluation of candidate portfolios.

B-14.9 PORTFOLIO DEVELOPMENT

In the planning phase, when preparing a long-term procurement plan, PG&E considers portfolio fit based on how well a particular resource provides the power products that need to be added to the portfolio. Not all resources provide the same products. For example, photovoltaic distributed generation and energy efficiency do not provide dispatchable peaking energy.

In the planning phase, PG&E first identifies the types and amounts of power products that it needs to fill its open position over the planning horizon. Those power products include energy products (baseload, peaking and shaping), capacity or Resource Adequacy (RA) products, and ancillary services products (*e.g.*, spinning, non-spinning, regulation, and black-start capacity). Then, PG&E identifies the energy products that

each alternative resource can provide (*e.g.*, baseload energy and dispatchable shaping or peaking energy.)

In the procurement phase, when evaluating transactions, portfolio fit can be a qualitative assessment or quantitative measure that represents how well a resource fits the portfolio's need. In addition to the market valuation, resources are compared based on their ability to meet the particular need being met, or their ability to provide additional features that are complementary to the portfolio. For example, if the proposed resource is not dispatchable by the utility, the offer with a generation profile that best matches the hourly profile of the open position will score more highly on PG&E's portfolio fit measure. Other portfolio fit considerations can include location and the volatility of the remaining portfolio open position.

PG&E developed 3 candidate plans designed to highlight trade-offs between reliability, environmental stewardship, and cost. The first plan meets all current basic state and regulatory requirements. In the second plan, PG&E procures to a higher than required level of reliability. The third plan includes the higher reliability level and more "preferred" (environmentally friendly) resources, relaxing the restriction that discretionary preferred resources must be cost-effective.

B-14.10 PORTFOLIO ANALYSIS

PG&E examined the 3 portfolios described above under 4 scenarios:

- Low market prices and low demand leading to stranded costs (due to more customers accessing Community Choice Access and Direct Access)
- Expected demand and price forecasts with low levels of "preferred" (environmentally friendly) resources available in the market
- Expected demand and price forecasts with adequate levels of preferred resources available in the market

- High market prices and high demand, with high levels of preferred resources available in the market.

PG&E calculates LOLP for each of the 3 candidate portfolios under each of the 4 scenarios, and finds that the first candidate plan exceeds the “most common utility planning standard” of 1-day-in-10-year LOLP in every scenario.

PG&E also measured risk due to fluctuation in load, gas and electricity price, and hydro availability for each candidate portfolio and each scenario using Monte Carlo analysis to a 95 percent confidence level.

B-14.11 PORTFOLIO SELECTION

Metrics used to evaluate the candidate plans include:

- Reliability and operational feasibility
- Compliance with State Loading Order requirements and RPS goals
- Cost
- Risk
- GHG emission levels

Candidate plans must meet the Commission’s adopted minimum 15-17 percent reserve margin under a load forecast for a 1-in-2 temperature peak. However, the recommend plan (the high-reliability, high-preferred-resources plan described above) goes further with a 16 percent reserve margin for a 1-in-10 temperature peak.

PG&E chose the preferred plan because of its: increased reliability; only modestly higher cost (1-2 percent rate increase), and; higher proportion of preferred resources which leads to a reduction in emissions, reduction in exposure to gas and electric price

volatility, and support for technological innovation for new renewable resources, all of which are clear policy preferences of the Governor, Legislature, and Commission.

B-14.12 ROLE OF REGULATOR

See Chapter 2.

B-14.13 STAKEHOLDER PROCESS

PG&E uses a 10-year planning horizon. Following a Commission guideline, PG&E files long-term plans on a biannual basis.

PG&E seeks the input of stakeholders on its procurement process. For example, a developer survey and conversations with other key stakeholders led PG&E to reduce credit requirements and make other changes to its renewables RFO. PG&E also released its transmission grid expansion plan to stakeholders. Stakeholders include State agencies, the CAISO, Participating Transmission Operators (PTOs), and others.

B-14.14 SOFTWARE

None discussed.

B-14.15 USE OF PROPRIETARY DATA

PG&E follows a confidentiality framework established through Rulemaking in 2003. According to this framework, the “only segment of the interested public whose access is somewhat restricted is composed of the suppliers and marketers who sell their energy-related products to, ultimately, California’s ratepayers. While participation of this segment in the resource planning process is necessary, granting full access to all information, including strategies along with other generator-specific information, is not.”³

Examples of the limited categories of information protected from disclosure to market participants are the utilities’ base case planning assumptions and peak day resource needs for only the first three years after filing.

B-15 Southern California Edison (SCE)**B-15.1 LOAD FORECASTING**

SCE used two load forecasts: a CEC forecast and an internally developed forecast. The SCE forecast includes both bundled sales and direct access loads, and was developed using econometric models with key variables for employment, population, electricity prices, weather, distributed generation, and DSM. Economic assumptions are derived from Global Insight forecasts. Volatility of the load forecasts was considered using historical data to calculate loads at the 95th, 50th and 5th percentile confidence levels.

B-15.2 NEEDS DETERMINATION

SCE determines need for the entire SP-26 area, of which the SCE portfolio need is a subset. The SP-26 region contains many load-serving entities, and SCE can not identify

³ Pacific Gas and Electric, *Resource Planning Issues*, p. 2-6. Undated document downloaded from PG&E web site at:

http://search.pge.com/cs.html?url=http%3A//www.pge.com/includes/docs/word_xls/b2b/wholesaleelectricitysuppliersolicitation/genresourceplanoir_test_pge_20040709-02-redacted-ch02.doc&qt=resource+plan&col=&n=1

the precise types of resources that should be procured, but at best can ensure that the regional perspective includes a sufficient amount of renewable and conventional resources to meet the needs of the portfolio sought by SCE. SCE determines needs under each of its two candidate plans.

SCE also determines needs for bundled service customers. Two perspectives on this are: (1) load minus existing and known resource commitments, and (2) load minus existing and known resources *and* future uncommitted resources, such as future RPS, DSM, and DG.

B-15.3 FUEL PRICE FORECASTING

SCE creates natural gas and electricity market price forecasts by blending forward market prices with long-term fundamental forecasts. In the case of natural gas, the long-term forecasts are taken from the average of forecasts provided by Global Insight, PIRA, and CERA. Electric prices come from a simulation dispatch model of the WECC area.

B-15.4 RESOURCE COST DEVELOPMENT

The resources modeled by SCE are not tied to any specific facilities, and they do not represent any specific technology or existing product. Rather, they are representative of resources that have cost and operating attributes suited to filling specific load requirements.

B-15.5 TREATMENT OF ENERGY EFFICIENCY

SCE takes a mixed approach to its treatment of DSM, reducing energy forecasts to reflect the presence of efficiency programs, but modeling demand reductions as a supply-side resource. For retail sales the forecast is reduced by the amount of energy efficiency. Load management and demand reduction programs are represented on the supply-side, and peak demand forecasts are not reduced to reflect their presence. However, a planning reserve adjustment is applied to reflect the fact that they are actually demand reduction programs.

B-15.6 MARKET PRICE RISK ASSESSMENT

For SCE, gas and electricity price forecast confidence intervals were derived by applying stochastic methods that consider long- and short-term parameters for volatility, correlation, and mean reversion. Short-term parameters are based on historical observations of real gas and power price data. Long-term parameters for gas are calibrated to match the one- and two-standard deviation forecasts provided by the vendors. Long-term parameters for power are based on the same parameters derived for natural gas because it is assumed that natural gas is predominately used to generate electricity, and the prices of natural gas and power are highly correlated.

Power and natural gas price volatility is derived using the EPRI two-factor model fit to volatility data based on historical daily forward prices. Three years of the most recent data is used to calculate the volatility input data – the standard deviation of daily log returns. Least square fit to volatility input data is used to estimate parameters of the two-factor model. Short factor parameters have monthly variation. Long factor parameters have no seasonality. The estimated parameters are used to estimate effective terminal velocities.

SCE also calculates TeVaR at the 99th percentile for power price, gas price, load, and supply availability. Whenever TeVaR exceeds 1.25 percent of the Consumer Risk Tolerance threshold, SCE consults with the PRG about steps to reduce TeVaR.

B-15.7 GHG REGULATION RISK

SCE does not specifically address GHG regulation risk. Differing levels of RPS and DSM are modeled in its portfolio candidates.

B-15.8 ENVIRONMENTAL ATTRIBUTES

Not discussed.

B-15.9 PORTFOLIO DEVELOPMENT

SCE created two candidate portfolios. The Required Plan achieves the 33 percent RPS goal by 2020 and Commission-ordered levels of DSM. The Best Estimate Plan assumes 20 percent RPS by 2020 and maximum reliably-achievable DSM. Each includes the same assumptions regarding fuel prices, retirements, contracts, future economic conditions, proportion of direct access, and reserve margin.

To build the portfolios, SCE first included the maximum amount of cost-effective DSM. Next, SCE added sufficient renewable resources to meet RPS goals. Then SCE added future contracts or resources that were announced as being pursued by a utility. The remaining need is met on a least-cost basis. The resources modeled by SCE are not tied to any specific facilities, and they do not represent any specific technology or existing product. Rather, they are representative of resources that have cost and operating attributes suited to filling specific load requirements.

B-15.10 PORTFOLIO ANALYSIS

SCE notes that the Commission's Scoping Memo requires consideration of how well plans (1) minimize ratepayer costs, (2) ensure reliability, and (3) minimize environmental impacts. To analyze cost, SCE measured the total revenue requirement across candidate plans and scenarios. Costs were compared across all confidence levels. SCE measured Expected Energy Not Served (ENS) to assess reliability. To measure environmental impact, SCE considered (a) a stochastic analysis of emissions, (b) the ability to meet RPS goals, (c) levels of demand response, and (d) the amount of energy efficiency.

B-15.11 PORTFOLIO SELECTION

SCE finds that the Best Estimate Plan results in lower costs under all scenarios and at all confidence levels. The Best Estimate Plan also has superior reliability, as measured by Expected Energy-Not-Served. While the Required Plan results in lower CO2 emissions, the extra cost is deemed excessive because much cheaper methods of carbon reduction

or offset exist. The two plans are found to “use similar levels of renewable power,” but the higher levels of renewables in the Required Plan are found to have “operational concerns and integration costs.” SCE finds the higher levels of demand response in the Required Plan to be based on “programs that are unlikely to materialize.” For these reasons, SCE chooses the Best Estimate plan.

B-15.12 ROLE OF REGULATOR

See Chapter 2.

B-15.13 STAKEHOLDER PROCESS

SCE conducts quarterly meetings with its Procurement Review Group (PRG) to discuss its forecasts, open position, changes in market conditions, and hedging strategies.

Additionally, SCE conducts ad hoc meetings as necessary. Current participants include:

- Commission’s Energy Division (ex officio)
- Division of Ratepayer Advocates (ex officio)
- The Utility Reform Network (TURN)
- National Resources Defense Council (NRDC)
- Coalition of Utility Employees (CUE)
- Union of Concerned Scientists (UCS)
- Aglet Consumer Reliance
- California Dept. of Water Resources (DWR)

B-16 San Diego Gas & Electric (SDG&E)

B-16.1 LOAD FORECASTING

The peak and demand forecasts used in SDG&E's LTPP were derived from the CEC's June 2006 demand forecast. The implied growth rates of this forecast were applied to the updated 2007 system demand levels to project loads through 2016. The change in SDG&E's forecasted percentage of bundled vs. direct access load is the same as what is assumed in the CEC forecast, re-based to year 2006 actual.

In addition, SDG&E develops high and low case forecasts, designed to reflect potential changes in overall demand and direct access and CCA load. The high case assumes 1 percent to 2 percent additional load growth for the first 3 years, declining thereafter – a range well within historical forecasting error. The low case models the potential for loss to direct access and CCA. Together, the high and low cases define a significantly wider range of outcomes than were present in the CEC's high and low case.

B-16.2 NEEDS DETERMINATION

SDG&E determines need by comparing its load forecasts to supply-side and DSM forecasts. To determine system-wide need (including direct access) SDG&E, having insufficient information to estimate energy requirements, examines capacity only, based on its role as a Participating Transmission Owner under the CAISO tariff.

B-16.3 FUEL PRICE FORECASTING

SDG&E's natural gas forecast is based on NYMEX forwards from 2007-2010, then blended with the 2011-2016 forecast used in the California Gas Report, which was based on an average of forecasts from the CEC, Energy Information Administration, and private consultants. Electric market prices are based on NYMEX SP-15 futures from 2007-2009. The implied heat rate based on electric and gas forwards from this period is then applied to the natural gas forecast to determine prices for the remainder of the forecast period.

B-16.4 RESOURCE COST DEVELOPMENT

SDG&E developed a MPR price for future renewable power. The prices were developed assuming a simple average of 10, 15, and 20 year contracts for all generic renewable resources added in a given year. SDG&E selected this price because it represents a price that would allow renewable power to be added a cost competitive with other options.

B-16.5 TREATMENT OF ENERGY EFFICIENCY

SDG&E subtracts energy efficiency and DSM, both committed and uncommitted, from the forecasted load.

B-16.6 MARKET PRICE RISK ASSESSMENT

SDG&E considers gas and electricity price risk at the 95th percentile, based on historical data from 2003-2006. The volatility from these years is applied to future years, and the 95th percentile is calculated for all plan years (2007-2016).

B-16.7 GHG REGULATION RISK

GHG regulation risk is not discussed. However, in evaluating the preferred resource plan, SDG&E notes that environmental impacts are minimized by adding resources according to the “loading order,” which favors energy efficiency, renewable resources, and clean fossil fuel generation in that order. Carbon and other emissions levels are reported.

B-16.8 ENVIRONMENTAL ATTRIBUTES

SDG&E has an internal goal to reduce GHG emissions by providing renewable resources beyond the required 20 percent.

B-16.9 PORTFOLIO DEVELOPMENT

SDG&E adds resources to its portfolios in the order outlined in the Energy Action Plan. The quantities of many of the resources are pre-determined by Commission or by State law. Conventional coal is eliminated as an option due to GHG emission limits.

SDG&E describes only one candidate portfolio – the Preferred Plan. This plan is determined by first subtracting from load target amounts of DSM, then adding in renewables sufficient to meet RPS standards, and finally adding the remaining resources necessary to meet load and reliability concerns on a least-cost basis. The specific renewable resources are not identified; rather the category is identified in the plan and an RFO will be held to select the specific resource.

B-16.10 PORTFOLIO ANALYSIS

SDG&E builds portfolios as described above to meet load under three scenarios related to its high, medium, and low load forecast. All scenarios contain the same assumptions regarding renewable prices, plant retirements, contract failure, and availability of new transmission. SDG&E qualitatively assesses the relative merits of adding resources to meet each load level. Since many of the resources are pre-determined, SDG&E is essentially deciding only on the timing of certain resource additions.

B-16.11 PORTFOLIO SELECTION

SDG&E selects a plan that adds capacity sufficient to meet the high load scenario. SDG&E determines that even in the low cases, this capacity is needed only 2 years later, and that therefore it is preferable and not excessively costly to plan for the high case.

B-16.12 ROLE OF REGULATOR

See Chapter 2.

B-16.13 STAKEHOLDER PROCESS

In developing its plan, SDG&E consulted in advance with a number of stakeholders including consumer groups, independent power developers, and environmental organizations. SDG&E also shared preliminary resource ranges with the San Diego Association of Governments.

B-16.14 SOFTWARE

None discussed.

Appendix C: Survey Sources

NWPCC. The Fifth Northwest Electric Power and Conservation Plan, May 2005.

PacifiCorp. 2007 Integrated Resource Plan, filed May 30, 2007.

Idaho Power. 2006 Integrated Resource Plan, Revised October 12, 2006; 2008 Integrated Resource Plan Update, Filed June 2008.

Puget Sound Energy. Integrated Resource Plan, Filed May 31, 2007.

Public Service Company Colorado. 2007 Colorado Resource Plan, filed November 15, 2007.

Avista Energy. 2007 Electric Integrated Resource Plan, August 31, 2007.

Arizona Public Service. January 2008 Resource Alternative Report; July 14 Interview with Brad Albert, APS Resource Planning.

Nevada Power Company / Sierra Pacific Power Company. 2006 IRP, 7th and 8th Amendments (filed in 2008) to 2006 IRP.

Public Service New Mexico. June 10, 2008, Draft Electric Integrated Resource Plan for the Period 2008-2027; July 16 Interview with Evelin Wheeler, Director of Environmental Sustainability.

Georgia Power. 2007 Integrated Resource Plan.

Seattle City Light. 2008 Integrated Resource Plan; 2006 Integrated Resource Plan.

Northern States Power. 2007 Resource Plan, filed December 14, 2007.

BC Hydro. 2008 Long Term Acquisition Plan (LTAP), filed June 13, 2008.

Pacific Gas & Electric. 2006 Long-Term Procurement Plan, March 5, 2007.

Southern California Edison. 2006 Procurement Plan, December 11, 2006.

San Diego Gas & Electric. 2007-2016 Long-Term Procurement Plan, December 11, 2006.

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1.1.1..1 Appendix D: List of Acronyms

ACC	Arizona Corporation Commission
AEO	Annual Energy Outlook
BACT	Best Available Control Technology
BCUC	British Columbia Utilities Commission
CAISO	California Independent System Operator
CARB	California Air Resources Board
CCA	Community Choice Aggregation
CCCT	Combined-Cycle Combustion Turbines
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Sequestration
CEC	California Energy Commission
CEM	Capacity Expansion Module
CEQA	California Environmental Quality Act
CERA	Cambridge Energy Research Associates
CHP	Combined Heat & Power

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California Consumer Power and Conservation Financing

CPA Authority

CPCN Certificate of Public Convenience and Necessity

CPUC California Public Utilities Commission

CRAG Conservation Resource Advisory Group

CREZ Competitive Renewable Energy Zones

CRR Congestion Revenue Rights

CSI California Solar Initiative

CUE Coalition of Utility Employees

DG Distributed Generation

Department of Energy, Energy Information

DOE-EIA Administration

DRA Division of Ratepayer Advocates

DSI Direct Service Industry

DSM Demand Side Management

DWR California Department of Water Resources

EAP II Energy Action Plan II

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EE	Energy efficiency
EIA	Energy Information Administration
EIR	Environmental Impact Report
EIS	Environmental Impact Statement
ENS	Expected Energy Not Served
EPA	Environmental Protection Agency
	Company name. Developer of the AURORA electric
EPIS	model.
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ESP	Electric Service Providers
EUE	Expected Unserved Energy
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
GED	Global Energy Decision
GHG	Greenhouse Gas

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GWH	Gigawatt Hour
HYSIM	Hydrological System Simulation Model
IEPR	Integrated Energy Policy Report
IGCC	Integrated Gasification Combined Cycle
IOU	Investor-Owned Utility
IPUC	Idaho Public Utility Commission
IRP	Integrated Resource Plan
IRPAC	Integrated Resource Plan Advisory Committee
IRPAG	Integrated Resource Plan Advisory Group
ISO	Independent System Operator
ISO-NE	Independent System Operator - New England
LCR	Local Capacity Requirements
LDC	Local Distribution Company
LNG	Liquid Natural Gas
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability

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LSE	Load Serving Entity
LTPP	Long Term Procurement Planning
LTRFO	Long-Term Request for Offer
MAPA	Multi-Attribute Portfolio Analysis
MAPP	Mid-continent Area Power Pool
MDL	Municipal Departing Load
MIT	Massachusetts Institute of Technology
MOO	Must Offer Obligation
MPR	Market Price Referent
MRTU	Market Redesign and Technology Upgrade
MWh	Megawatt Hour
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
NPC / SPPC	Nevada Power / Sierra Pacific Power
NQC	Net Qualifying Capacity
NRDC	National Resources Defense Council

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NREL National Renewable Energy Lab

NWPCC Northwest Power and Conservation Council

NYISO New York Independent System Operator

NYMEX New York Mercantile Exchange

OATT Open Access Transmission Tariff

OPR Office of Planning and Research

OPUC Public Utility Commission of Oregon

OTC Once-Through Cooling

PBA Power Bridging Agreements

PIEPC Provincial Integrated Electricity Plan Committee

PIRA Petroleum Industry Research Associates

PNM Public Service Company of New Mexico

POLR Provider-of-Last-Resort

POU Publicly Owned Utility

PRG Procurement Review Group

PRiSM Preferred Resource Strategy Linear Programming Model

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PRM	Planning Reserve Margin
PRSG	Midwest Planning Reserve Sharing Group
PSM	Portfolio Screening Model
PTC	Production Tax Credit
PUCN	Public Utilities Commission of Nevada
PURPA	Public Utilities Regulator Policy Act of 1978
PV	Present Value
PVRR	Present Value Revenue Requirement
QF	Qualifying Facility
RA	Resource Adequacy
RAP	Resource Acquisition Period
RAR	Resource Adequacy Requirement
REC	Renewable Energy Credit
RETI	Renewable Energy Transmission Initiative
RFI	Request for Information
RFO	Request For Offer

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RFP	Request for Proposal
RMR	Reliability Must Run
RPM	Reliability Pricing Model
RPS	Renewable Portfolio Standard
RRC	Regional Reliability Council
RTEPP	Regional Transmission Expansion Planning Process
RTO	Regional Transmission Organizations
SAE	Statistically-Adjusted End-Use
SCAQMD	South Coast Air Quality Management District
SCCT	Simple-Cycle Combustion Turbines
SCE	Southern California Edison
SCL	Seattle City Light
SDR	Social Discount Rate
SGIP	Self-Generation Incentive Program
SOAP	Simple Object Access Protocol
SOS	Standard Offer Service

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T&D	Transmission and Distribution
TAG	Technical Assessment Guide
TeVAr	To-expiration-Value-at-Risk
TRC	Total Resources Cost
TURN	The Utility Reform Network
UCS	Union of Concerned Scientists
USDOE	United States Department of Energy
WACC	Weighted Average Cost of Capital
WECC	Western Electricity Coordinating Council
WI	Western Interconnect
WUTC	Washington Utilities and Transportation Commission

(END OF ATTACHMENT 1)