Exploring the relationship between planning and procurement in Western U.S. electric utilities

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Abstract

Integrated resource planning (IRP) is an important regulatory process used in many U.S. states to formulate and evaluate least-cost and risk-assessed portfolios to meet future load requirements for electric utilities. In principle, effective implementation of IRP seeks to assure regulators and the public that utility investment decisions, given uncertainty, are as cost-effective as possible. However, to date, there is no empirical assessment on the effectiveness of IRP implementation. In this analysis, we compare planning, procurement processes and actual decisions for a sample of twelve load serving entities (LSEs) across the Western U. S. from 2003-2014. The 2008/2009 recession provides a unique "stress test" to the planning process and offers an excellent opportunity to trace how procurement decisions responded to this largely unforeseen event. In aggregate, there is a general alignment between planned and procured supply-side capacity. However, there are significant differences in the choice of supply-side resources and type of ownership for individual LSEs. We develop case studies for three LSEs and find that subsequent plans differ significantly due to changes in the planning environment and that procurement decisions in some cases are impacted by factors that are not accounted for in the planning process. Our results reveal that a limited amount of information produced during the long-term planning process (e.g., forecasts, methods, and least cost/risk portfolios) are ultimately used during the procurement process, and that the latter process relies extensively on the most recent information available for decision making. These findings suggest that states' IRP rules and regulations mandating long-term planning horizons with the same analytical complexity throughout the planning period may not create useful information for the procurement process. The social value of a long-term planning process that departs from procurement and the balance between transparency and complexity of the planning and procurement processes is an open question.

Keywords: resource planning, procurement, case study, regulation, retrospective analysis.

Executive Summary

Planning and procurement are two fundamental activities conducted by utilities to fulfill their public service mission of providing reliable and affordable electricity. It is generally recognized that integrated resource planning (IRP) is a stakeholder-driven process that provides guidance for future procurement decisions that, in principle, assure that future resources are least cost and risk. It follows that achieving these objectives requires the planning process to produce and transfer information that is useful for the procurement process. However, to the best of our knowledge, there has been little or no research conducted that assesses the effectiveness (or usefulness) of resource plans by tracing their relationship to procurement decisions made after the plan was originally filed.

Procurement decisions made by the load serving entity (LSE) may—and often—deviate over time significantly from the plans that preceded them. On one hand, this difference between planning and procurement may reflect a prudent decision to adapt to evolving conditions as new information becomes available. On the other hand, it is reasonable to ask what the value of IRP is, if actual procurement decisions are expected to differ significantly from those originally proposed in the IRP. Accordingly, we were motivated by the following questions:

- What types of technical, economic, and regulatory information are considered in both long-term planning and procurement decisions? In short, how are plans used by electric utilities for procurement?
- How much does it actually matter—in terms of cost-effectiveness, efficiency, and accountability—if long-term plans are not followed when procuring new resources? To whom should these potential differences matter?

In this analysis, we compare the resource acquisition recommendations from IRPs filed in the early-to-mid 2000s to the actual procurement decisions that followed. We assess differences in timing and type of resource acquisition, as well as whether the resource was owned by the utility or contracted via a power purchase agreement. We follow this comparison with case studies of three jurisdictions. More specifically, we examine utility, regulatory, and other stakeholder regulatory filings to understand the reasons reported by utilities that explain deviations between their originally-filed plans and their efforts to procure actual resources. In analyzing the case studies, we specifically look for information flows from the planning to procurement phases that provide support for these deviations and shed light on the empirical relationship between these two processes.

We find that, in aggregate, planning and procurement levels were similar for the 12 LSEs considered in this analysis (see Figure ES-1). However, the aggregate mix of procured resources exhibited greater reliance on natural gas-fired generation and less on coal-fired generation than originally planned. In addition, we find that three times more wind capacity was procured compared to what was originally planned. We find that the substitution from coal to natural gas-fired combined-cycle combustion turbines (CCCTs) was possibly driven by an *anticipated* reduction in natural gas prices starting around

2007. Adoption of less-efficient simple-cycle combustion turbines (SCCTs) are correlated with *actual* price reductions realized after 2008. In addition, increased deployment of SCCTs may also be closely related to the need to provide balancing capabilities given higher penetration of intermittent resources like wind. In summary, we find that natural gas prices impacted the mix of resources, but do not appear to have had a significant effect on the amount of procured capacity, when compared to resources that were originally identified in the integrated resource plans.

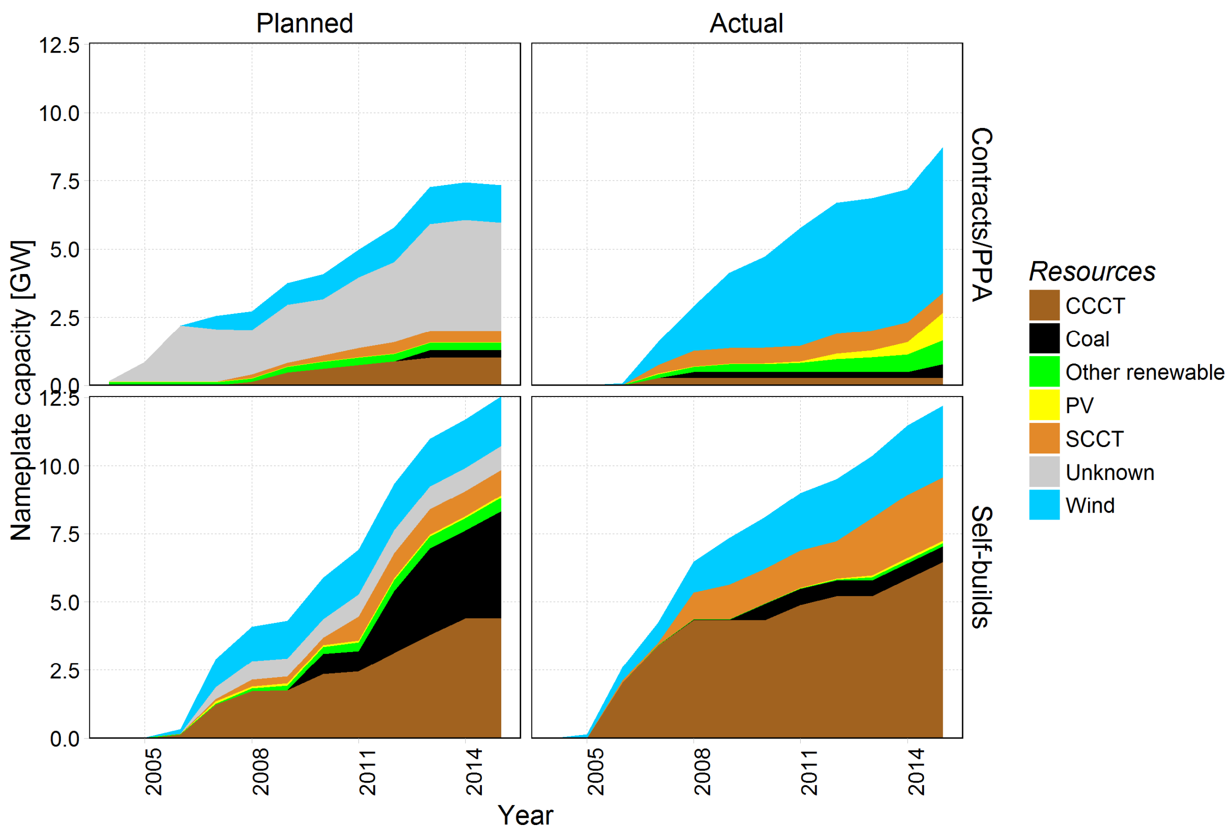

Figure ES-1. Total incremental actual (procured) and planned nameplate capacity by resource and split by contracts and self-builds for 12 Load Serving Entities in the West

Examining planning and procurement by resource and by individual LSE, however, reveals a much wider variation that is not apparent from the aggregate analysis. We study the regulatory record to understand what explains these differences for three LSEs operating in the Western United States: Sierra Pacific, Idaho Power, and Avista. We find that differences are explained by uncertainty in several key parameters, the challenges in managing this uncertainty, and the variation in risk management methods employed in the planning and in procurement phases, respectively. Differences in levels of procurement were largely related to load growth, particularly from industrial customers, but also influenced by economic performance. Differences in resource mix largely arise from regulatory decisions related to Renewable Portfolio Standards (RPS) and Demand Side Management (DSM) targets, but also from relative fuel price differentials.

We find that most information produced in the planning phase is generally disconnected from the procurement phase. Connections between IRPs and specific procurement activities are for the most part rather informal—in terms of quantitative information used or processes. In some cases, utilities may seek and/or exploit cost-efficient procurement opportunities that were not specifically planned for or identified in their most recent IRP. In their procurement decisions, utilities generally attempt to weight current technical, economic, and regulatory information more heavily than on information produced during the original planning phase. We find that plan "updates"—for all of the cases considered in this study—were significantly revised within a two-to-three year period after the original plan was filed in response to changes customer load, the regulatory environment, and other economic conditions.

A more careful evaluation of the links between integrated resource planning and procurement is an important research area as energy technologies, markets, and policy and regulatory goals evolve and become more complex. Efforts to make IRP more complex may not be warranted without formalizing and structuring the flows of information between planning and procurement and their value. While our analysis sheds light on the current status of these flows, determining the value of information and proper regulatory structures is an open area of applied research. There is a tension, if not inconsistency, between making IRP more useful to the procurement process – and hence more transparent – and the production of more information from an increasingly complex process. The balance between these two objectives will have major policy implications for the efficiency and effectiveness of planning and procurement process for regulated electric utilities.

While this study has focused on examining and understanding the practical connection between planning and procurement, our analysis has also revealed several promising research directions. Acquisition of natural gas units by LSEs seems to be explained by a mix of the relative efficiency of turbines, their use as baseload or peaking units, and natural gas prices. Research into organized wholesale markets in certain regions of the U.S. suggests that these same factors may explain investment decisions in competitive generation supply (Borenstein and Bushnell, 2015; Hill, 2016). This finding highlights the need to conduct research into, for example, intra-day market transactions, which are actively used by some LSEs as hedging mechanisms for the short-term. However, these non-firm transactions are neither part of the planning process nor subject to the same scrutiny as firm procurement decisions. The impact of these transactions in a comprehensive procurement strategy, their connection to planning, and the costs and benefits for different stakeholders are an important area worthy of additional research. We believe this paper and these additional research venues will provide much needed empirical evidence for the assessment and improvement of procurement practices in the electric utility industry.

1 Introduction

1.1 Background

Integrated Resource Planning (IRP) evolved in the late 1980s and 1990s from least-cost planning (LCP). LCP was originally introduced in the 1970s as a means of ensuring that demand-side measures to reduce electricity consumption—especially end-use energy efficiency—were also considered by utilities in their effort to meet the electricity needs of their customers (e.g., see Hirst, 1996, 1990; Hirst and Goldman, 1991; Swisher et al., 1997). IRP expanded utility planning analytical methods and stakeholder review processes in order to, among other purposes, provide more information to regulators, facilitate greater stakeholder engagement, and take better account of risk and uncertainty affecting electricity production, consumption, and cost. These different objectives would lead to cost-effective and socially-efficient procurement decisions by utilities (Swisher et al., 1997). It follows that achieving these objectives and outcomes would require the planning process to produce and transfer information that is useful for the procurement process.

Over the last several decades, IRP has become a technically and computationally complex set of methods, techniques, results, and stakeholder communication strategies. For example, a recent study documented the heterogeneous evolution in complexity of load forecasting techniques for different utilities (Carvallo et al., 2016). For some load-serving entities (LSEs), this has been reflected in the length of their plans and corresponding appendices having grown ten-fold over the past twenty years. The complexity evident in newer plans must be assessed against the benefits that these plans and supporting processes provide.

An assessment of complexity is an integral part of a broader assessment of the usefulness of IRP. Core electric utility business model and regulatory framework paradigms have been challenged since the deregulation movement in the late 1990s. More recently, rapid adoption and integration of distributed energy resources (DER) is promoting a similar review. Rooftop photovoltaic panels, ubiquitous demand response, and, in the near future, energy storage and electric vehicles, are challenging current practices including planning processes (Kahrl et al., 2016). It follows that it is critical to assess the extent to which resource plans filed by electric utilities are achieving their primary objectives as stated and whether the complexity is helping or deterring their achievement. As a first step, assessments of IRPs should be conducted to ensure that they continue to fulfill the role that they were designed to perform in light of this rapidly evolving industry.

The literature on integrated resource planning has focused in assessing plans for over three decades. Early assessments of integrated resource plans were largely normative. They aimed to suggest a minimum set of activities and components for the analysis and were concerned in great detail about the tools and models used (Cohen et al., 1990; Eto, 1990; Hirst et al., 1991; Hirst and Goldman, 1991; Hobbs, 1995; Hoog and Hobbs, 1993; Kahn, 1995; Kreith, 1993). As more plans were filed and publicly accessible, cross-comparison to extract best practices was also undertaken both in earlier and more recent assessments (Aspen and E3, 2008; Hirst et al., 1990; Hirst, 1994; Wilkerson et al., 2014; Wilson and Biewald, 2013; Wilson and Peterson, 2011). The literature on IRP has also focused on specific topics within the planning process, such as greenhouse gas regulation (Barbose et al., 2009), treatment of demand side resources (Barbose et al., 2008; Eckman, 2011; Gellings and Smith, 1989; Lamont and Gerhard, 2013; Satchwell and Hledik, 2014), transmission planning (Baldick and Kahn, 1992; Mills et al., 2011), management of uncertainty (Hirst and Schweitzer, 1990; Wilkerson et al., 2014), load forecast performance (Carvallo et al., 2016), and distributed resources (Mills et al., 2016). When assessing actual plans filed by electric utilities, existing research benchmarked them against (1) a normative definition of IRP or (2) among themselves. These assessments verify whether plans submit to a certain standard, but they cannot verify whether the objectives of resource planning are being achieved. We believe this inability to verify whether IRP objectives are being met is an important gap in the literature.

In this paper, we assess resource plans by employing a method that compares planning outcomes to procurement decisions and the regulatory processes that connect them. This novel approach has never been carried out, although it was recognized early on in the literature as the proper approach to assess plans: "Ideally, utility plans should be assessed on the basis of the utility's resource acquisition activities. But integrated resource planning (IRP) is so new that insufficient implementation has as yet resulted from these plans." (Hirst et al., 1990, p. 1). Another gap in the literature is the overwhelming focus on the models, analysis, and contents – ultimately, the outcome – of the plans themselves, but not on how this outcome relates to the planning process. In our literature review, we find only one paper that studies the planning process and outcomes in detail (Hirst, 1989), but even then it was only for a single utility and jurisdiction.

In this analysis, we quantitatively compare the acquisition recommendations of IRPs conducted in the early- to- mid- 2000s to the actual procurement decisions that followed over the next 15 years. We assess differences in timing and type of resource acquisition, as well as whether the resource was owned by the utility or under contract with a third-party. We then conduct qualitative case studies of three jurisdictions, examining regulatory filings to understand the planning process and the reasons reported by utilities to explain deviations between their originally-filed plans and their later applications to procure actual resources.

We recognize the limitations of this method and our analysis. This analysis is not intended to verify if and how IRP is meeting or has met each one of the utility's or regulator's stated objectives. The goal of this study is to explore the "connection" between planning and procurement in order is to understand what type of information is produced, transferred, and ultimately used by each process. We understand this "connection" as empirical evidence in the regulatory record that the information created during the planning process is useful as feedback into the procurement process[1]. Assessing this connection provides direct evidence on the actual application of IRP as a regulatory planning tool. In addition, this

[1] We acknowledge this is not the only method to gather evidence. It is possible that the regulatory filings do not reflect flows of information that take place over verbal discussions between regulators and utilities or other instances. An alternative approach could include interviews with regulators and utility planners to uncover other flows of information. However, the regulatory record in the jurisdictions analyzed is quite thorough and we are confident that it is an appropriate method to capture these flows.

assessment provides indirect evidence on the degree into which some of the objectives of IRP are being fulfilled.

1.2 Overview of a planning and procurement process

One important objective of the planning process is to provide critical feedback to the activities related to procurement of resources by utilities[2]. Procurement processes can vary across jurisdictions, but are generally described as the procedure under which utilities apply to and regulators approve the physical (or financial) acquisition of resources to meet their load and reliability obligations. These resources can include electric generating units, transmission lines, contracts to purchase energy and/or firm capacity, rights to transmit and distribute electricity, and programs to implement (or incentivize) demand-side resources. Historically, regulators of electric utilities in the U.S. have employed a statutory prudency standard to approve or reject procurement of resources. Regulatory commissions use the best information available at a given time to authorize or reject acquisition of resources by utilities (ORNL, 1987).

It is generally assumed that planning and procurement practices typically follow a simple sequence: plan first and then procure the resource. In reality, however, the relationship between planning and procurement is more complex due to the design and inherent dynamics of each process. First, long-term planning is an ongoing activity whose output (especially resource acquisition recommendations) changes from one period to the next depending on variations in uncertain input variables (e.g., price of natural gas), economic conditions (e.g., variation in regional economic activity), technological development (e.g., electric vehicles), and policy and regulatory environments. Second, the dynamic nature and price volatility of the contracting models that utilities are required to consider when evaluating resource alternatives makes the actual procurement process challenging and hard to anticipate during the planning phase (Graves et al., 2004). In addition to building their own generation, utilities often acquire resources from a number of external entities with very different risk profiles including a mix of customers (residential, commercial, and industrial), wholesale markets, independent power producers, and neighboring LSEs. Finally, in some jurisdictions, there is an explicit and well-defined connection between planning outcomes and procurement decisions, while in other jurisdictions there may be a less formal and more flexible relationship between these activities.

In either case, procurement decisions by an LSE may deviate over time significantly from the plans that preceded them. On the one hand, this may reflect a prudent adaptation to evolving conditions, as new information becomes available that indicates the need for alternative cost effective procurement choices. Clearly, procurement decisions may be sub-optimal (i.e., not least-cost or lowest-risk) if utilities do not adjust their plans in this manner. On the other hand, it is reasonable to ask why very complex and costly IRP processes are warranted if actual procurement decisions are expected to differ significantly from those proposed in IRPs. Accordingly, the analysis discussed in this paper is motivated by the following questions:

[2] Other objectives outside the scope of this paper include informing least-cost operation and the assessment of risk to the current portfolio.

- What are the technical, economic, and regulatory information flows that complex integrated resource planning procedures and processes produce for procurement? In short, how are plans used by electric utilities for procurement?
- How much does it actually matter—in terms of cost-effectiveness, efficiency, and accountability—if long-term plans are not followed when procuring new resources? To whom should these potential differences matter?

This paper is the second in a series released by LBNL related to integrated resource planning and procurement. The first, which discussed load forecasting in IRP and its relationship with acquisition, largely focused on the *inputs* to the resource planning process (Carvallo et al., 2016). This study focuses on the *outcomes* of the planning phase, and their relationship to the physical and contractual procurement of resources. We believe that this analysis will inform stakeholders who are interested in understanding the overall IRP process or elements thereof and shed light on the application of resource planning by utilities in their procurement of new resources. We also aim to contribute to enhancing the ability of IRP to respond to rapidly changing electricity industry, technological, economic, and regulatory environments.

This paper is organized as follows. In section two, we identify data sources and specify a methodology. In section three, we perform a quantitative comparison between planning and procurement of resources for twelve Western U.S. LSEs. Section four contains the case studies of three LSEs that are chosen based on results from section 3. We discuss the results and implications in section five. The study concludes in section six with a summary of findings and suggestions for further research.

2 Data sources and methods

The objective of this paper is to assess the usefulness of plans by understanding their connection to procurement. Methodologically, this paper is based on two parallel analyses. First, a quantitative comparison between planning and procurement is performed for twelve LSEs that are representative of the Western U.S. Next, we conduct in-depth case studies for three of these LSEs, which operate in different states—Nevada, Washington, and Idaho.

The quantitative analysis of planning and procurement relies largely on two types of data: projected (planned) and actual[3] values. We collect projections from integrated resource plans that were made roughly a decade ago—from 2003 to 2007—by twelve LSEs across the Western Electricity Coordinating Council (WECC). We use the same sample of LSEs and criteria as in a preceding paper (Carvallo et al., 2016). The selected LSEs represented 34% of 2014 sales and served 32% of 2014 retail customers within the jurisdiction of WECC. We exclude the three large California investor-owned utilities, because the California planning framework is fundamentally different from the other resource planning mandates in WECC (Aspen and E3, 2008).

3 We refer to these also as "realized" or "observed" throughout the paper.

We select IRP filings that are old enough to allow a reasonable period of comparison with actual quantities and timing of resource procurement through 2014, the most recent year for which these values are available. Depending on the LSE, between seven and eleven years of observed resource procurement can be compared to the original results from the respective plans (see Table 1). We also examine subsequent or intermediate resource planning filings to trace their evolution into potential procurement decisions (see Section 4 for more details). Finally, we use a more recent IRP as a way to compare existing resources and validate contract and power purchase agreement (PPA) information.

Table 1. LSE integrated resource plans analyzed in this study.

LSE Acronym	LSE name	Plan year	Reference
Avista[a]	Avista Corporation	2005	(Avista, 2013; 2005)
COPSC	Public Service Company of Colorado (Xcel Energy)	2003	(COPSC, 2011; 2004)
Idaho[a]	Idaho Power Company	2006	(Idaho, 2013; 2006)
LADWP	Los Angeles Department of Water and Power	2006	(LADWP, 2012; 2006)
NVPower	Nevada Power Company	2006	(NVPower, 2012; 2006)
NW	NorthWestern Corp. dba NorthWestern Energy	2004	(NW, 2013; 2004)
PacifiCorp	PacifiCorp	2004	(PacifiCorp, 2015; 2005)
PGE	Portland General Electric Company	2007	(PGE, 2014; 2007)
PNM	Public Service Company of New Mexico	2007	(PNM, 2011; 2007)
PugetSound	Puget Sound Energy, Inc.	2005	(PugetSound, 2013; 2005)
Seattle	Seattle City Light	2006	(Seattle, 2012; 2006)
SierraPacific[a]	Sierra Pacific Power Company	2004	(SierraPacific, 2013; 2004)

[a] LSE that is analyzed further in the in-depth case studies.

Following Carvallo et al. (2016), the year for the selected plan is based on several criteria: the plan is old enough to allow a meaningful comparison with observed values, but not too out-of-date that the effects of deregulation in the late 1990s became a confounding factor or that our findings are not relevant to present-day IRP processes and procedures. The analysis period includes the 2008 economic crisis, which was expected to create important differences between plans developed before and procurement decisions made after it. However, there is evidence that planning and procurement levels and timing were quite similar after aggregating results from the LSEs in our sample (Carvallo et al., 2016). Regardless, the 2008/2009 U.S. recession still provides a unique “stress test” to the planning process and offers an excellent opportunity to trace how procurement decisions responded to this largely unforeseen event.

2.1 Forecast and outcome information from plans

Two basic types of forecast and outcome information are collected from each IRP: supply-side resources and natural gas prices. The supply-side resources are essentially the supply-side portion of the preferred portfolio identified by LSEs in their long-term resource plans[4]. The data used for this analysis includes the type of supply-side resource, the expected installed or purchased capacity[5], and the online year. We record nameplate or nominal capacity because de-rating factors for firm capacity vary widely across LSEs (Mills et al., 2016) and also because nameplate capacity is correlated with investment levels. We take account of whether the resource was planned to be owned by the utility or acquired through some type of contract with an outside party.

For natural gas prices, we use the base or reference price whenever available, in dollars per MMBtu. LSEs typically provide forecasts for the Henry Hub, but in the case when they use a different local pricing hub, we account for delivery to that hub from Henry and adjust prices accordingly to reflect all prices at the Henry Hub. Two out of the twelve LSEs in our sample did not provide a publicly-available natural gas price forecast.

2.2 Information on actual procurement

Information on actual procurement decisions were obtained primarily from the "Velocity Suite" system supplied by ABB-Ventyx. This is an online database system that compiles publicly-available data and also contains proprietary values for variables that are not always publicly-available, including retail fuel prices and marginal costs (ABB-Ventyx, 2016).

The Velocity Suite system contains electric generation unit (EGU) and PPA[6] data that are typically reported through the Energy Information Administration (EIA) Form 861[7] and NERC Electricity Supply and Demand (ES&D) database. For EGUs, we use the plant owner name to identify the owner LSE. We use the first commercial online date and the last retirement date to pinpoint the installation year and retirement year for the unit, respectively. For PPAs, we use a proprietary dataset developed by ABB-Ventyx that records publicly-available data for these types of transactions. This dataset contains the buyer name – used to identify the purchasing LSE in our sample – and characteristics of the resource being purchased including summer/winter capacity, contract length, and fuel type.

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[4] LSEs usually design and evaluate, technically and economically, several different resource portfolios. The least-cost and lowest-risk portfolio is usually labeled the "preferred" portfolio and serves as a recommendation for future resource acquisitions.

[5] In the case when both winter and summer capacities are reported, we systematically recorded the highest value as the planned capacity.

[6] Power purchase agreements or PPAs are a generic term used to describe long term agreements between utilities and other entities to acquire firm or non-firm energy and capacity.

[7] As defined by the EIA, "The Form EIA-861 and Form EIA-861S (Short Form) data files include information such as peak load, generation, electric purchases, sales, revenues, customer counts and demand-side management programs, green pricing and net metering programs, and distributed generation capacity." (EIA, 2016).

2.3 Sources for case studies

We conduct in-depth case studies based on actual resource plans from three LSEs as well as other documentation filed by the companies in compliance with their regulatory obligations relative to resource planning and procurement. Resource planning information from the following LSE/jurisdictions combinations were evaluated in this analysis: Sierra Pacific (Nevada); Avista (Idaho and Washington); and Idaho Power (Idaho and Oregon). Selection criteria and details about how we conducted the case studies are presented in Section 4.

3 Comparison between planning and procurement

We start by empirically assessing how planning has compared to actual procurement decisions for our sample of 12 LSEs. We compile incremental capacity expansion planning data from plans developed in 2003-2007 for 12 different LSEs in the Western U.S. (for more details see Section 2 and Table 1). The focus of this analysis is on supply-side power plants and contracts that are part of the preferred portfolio in a given IRP. We collect and organize this data using the Resource Planning Portal[8]—an online system developed by LBNL that houses long-term planning assumptions from 2003 to the present for dozens of utilities operating across the Western U.S.

We compare this planning data against actual incremental capacity expansion and firm contracts/PPAs, obtained from different public sources (see Section 2). We estimate the sum of the incremental resource additions carried out by each LSE, as well as the type of resource starting from the same first year as analyzed in the corresponding resource plan (see Table 1). We compare the *timing*, *size,* and *type* of each incremental supply-side resource with the corresponding planned procurement in the LSE's IRP (from the selected base year). We track actual contracts by identifying the buyer in the Ventyx dataset of PPAs signed in the past 15 years and then by tracing the resource type purchased.

Carvallo et al. (2016) analyzed aggregate outcomes for planning and procurement and found that they were fairly similar both in level and timing during the study period. In aggregate, LSEs had planned for a nameplate expansion of ~ 20 GW by 2015 and a similar amount of capacity was actually realized (18 GW). The mix of self-builds and contracts was also very similar between planning and procurement, with one third for contracts and two thirds for owned resources. Contrary to what might have been expected, we find that the severe economic recession that began in 2008-2009 did not significantly affect procurement relative to what was planned under different economic conditions (Figure 1).[9]

We expand upon the aforementioned analysis by including the type of resource that was planned and ultimately procured. From this comparison, several notable trends emerge. First, much of the planned coal capacity ended up instead being replaced by natural gas units. We find that planners in the mid-

[8] See http://resourceplanning.lbl.gov

[9] This is consistent with the retrospective load forecast accuracy analysis for this sample of LSEs in Carvallo et al. (2016), which found that the reductions in load growth following the onset of the recession did not significantly affect the utilities' load forecasts until several years later.

2000s correctly anticipated that natural gas would be an important part of the expansion in the Western U.S. In some cases, this occurred because LSEs projected significant reductions in natural gas prices that would justify increased procurement of natural gas resources (see Figure 2). Difficulties in coal-based generation deployment due to permitting, air quality standards, and stakeholder concerns regarding greenhouse gas emissions from coal generation were also mentioned by several LSEs in their earlier resource plans. It is possible that since combined-cycle natural gas units can perform a similar baseload role to coal units, that plans indicated that natural gas-fired generation would increase in lieu of new coal generation.

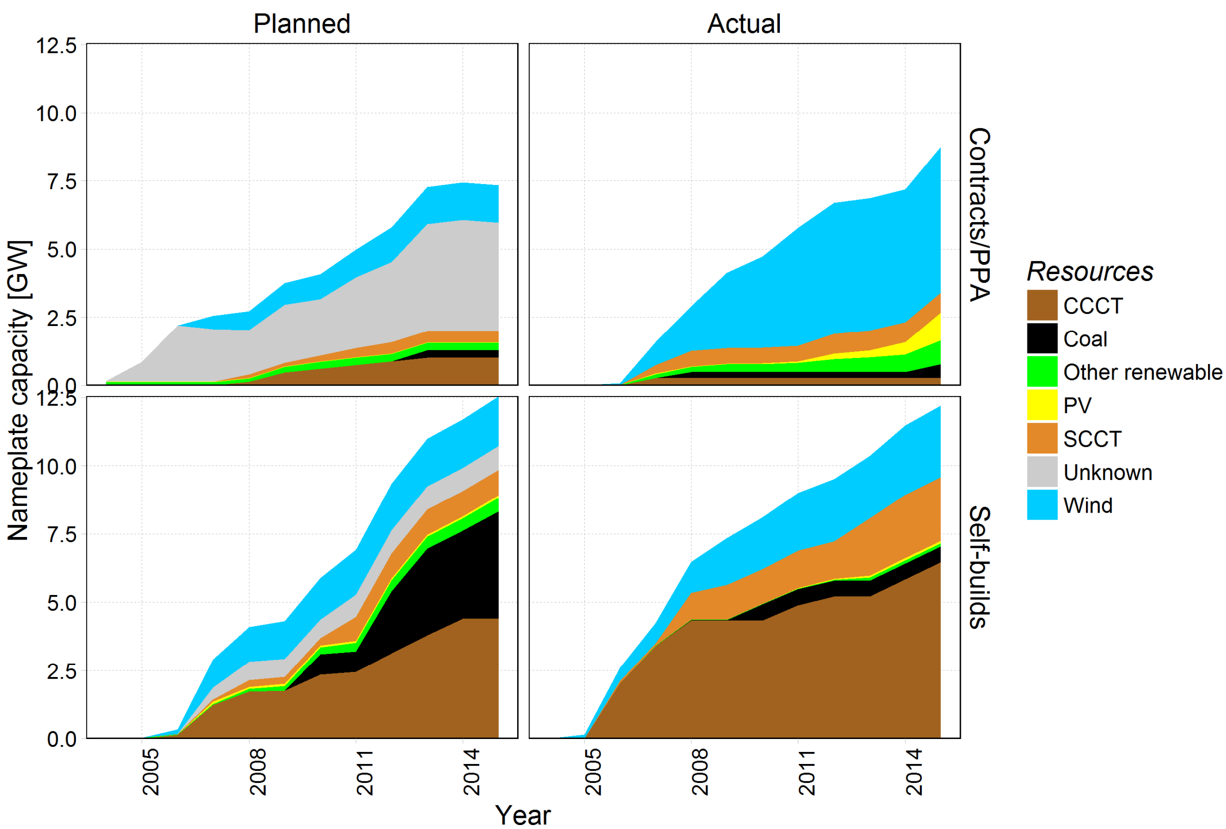


Figure 1. Total incremental actual (procured) and planned nameplate capacity by resource and split by contracts and self-builds.

Second, wind resources were procured in larger quantities than originally planned. The expected nameplate expansion by 2015 was roughly 20% coal, 35% natural gas, 15% wind, and 25% undefined resources[10], with minor contributions from renewable resources not related to wind. The actual expansion was approximately 50% wind with some additional renewables and 50% natural gas with some coal-based generation. We compare the timing and size of unspecified planned resources and find that it is very likely that wind PPAs were the source of this new capacity. Wind shows strong growth

[10] LSEs use contracts or market purchases as least-cost resources when their expected wholesale electricity cost is relatively low. In some cases, they cannot differentiate the type of resource they are acquiring on an open market transaction.

during and after the 2008 recession, perhaps as a consequence of a mix of production tax credits, new renewable portfolio standard targets, reduced prices for wind PPAs, and reduced installation costs (Wiser and Bolinger, 2016). This larger-than-expected share of wind resources may explain the larger adoption of peaking gas units when compared to planned units (see share of simple-cycle combustion turbines (SCCT)—or "peakers"—in Figure 1). These units typically play an important role in providing rapid response and flexibility to balance the potential short-term variability of wind resources (Mills and Seel, 2015). However, there are other possible explanations for the higher SCCT actual resource acquisition, including the faster deployment, reduced capital costs, and, as mentioned, lower natural gas prices after 2008.

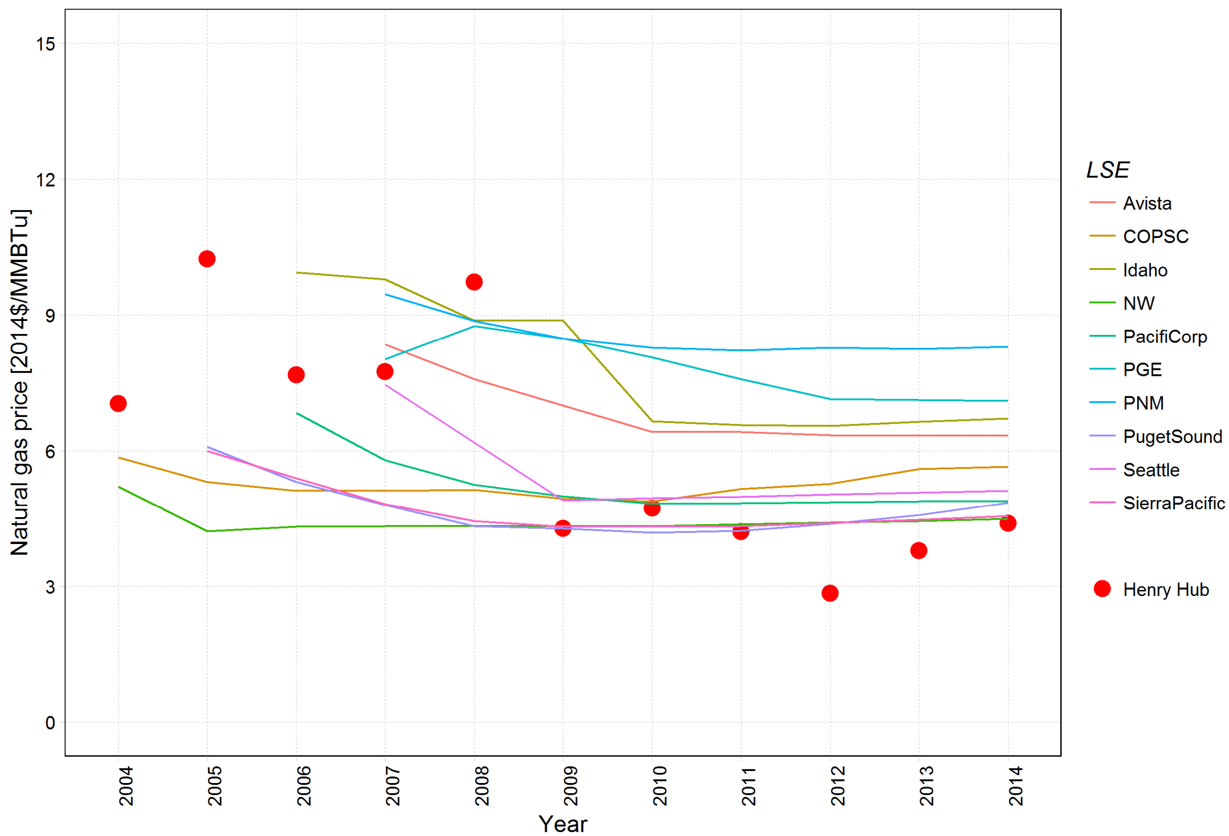


Figure 2. Forecasted and average annual actual natural gas price for 2004-2014 at Henry Hub.

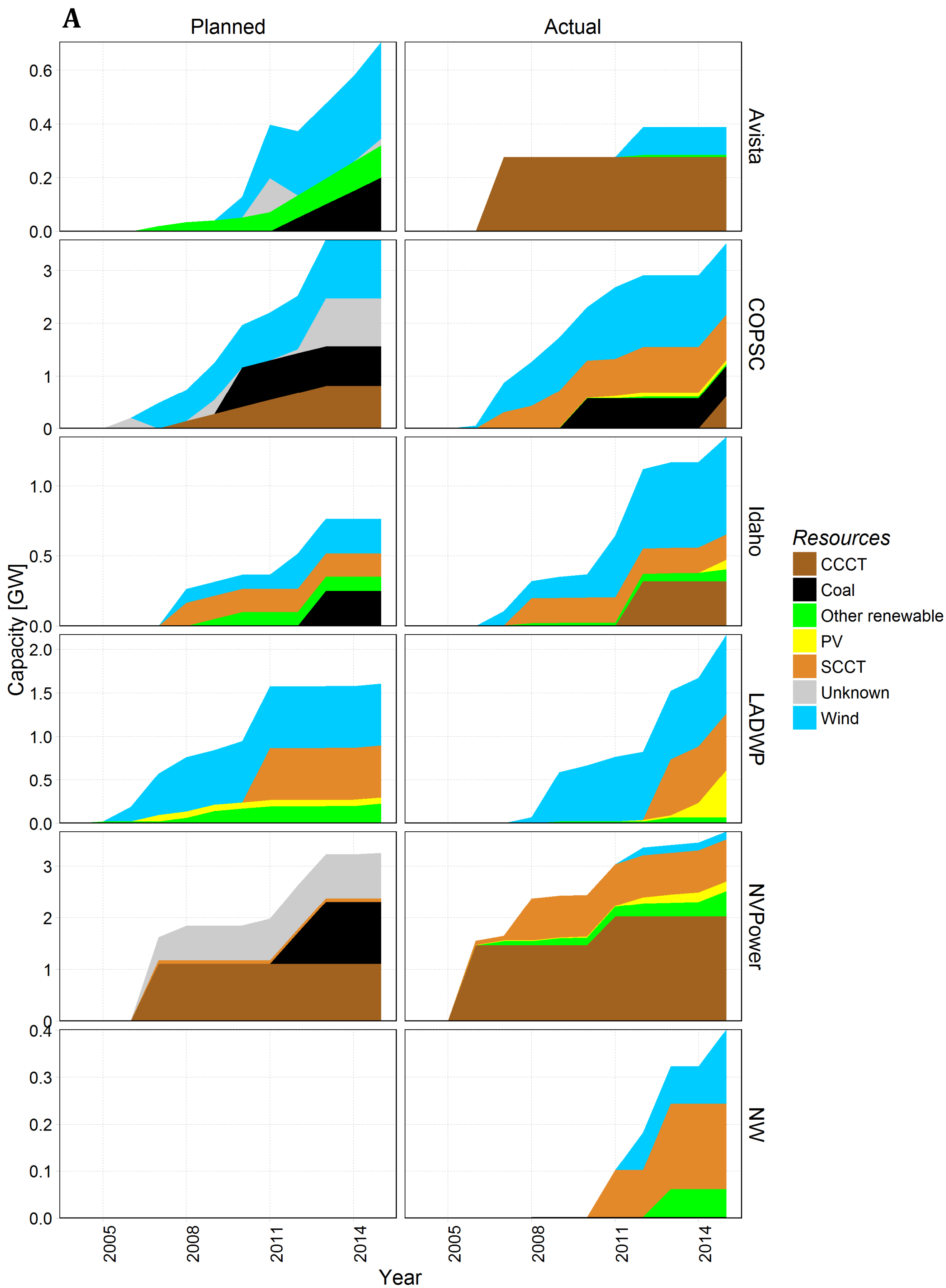
Third, over 80% of the new capacity in combined-cycle combustion turbines (CCCTs) was deployed before natural gas prices actually dropped in 2009 (see Figure 2). At the same time, most LSEs were forecasting natural gas prices to drop from their 2004 levels of $6-7/MMBtu to around $4/MMBtu. This suggests that most of the investment in CCCTs may have been made following these forecasts rather than the LSEs waiting for prices to actually drop. In contrast, most of the investment in less-expensive, but also less-efficient simple-cycle combustion turbines (SCCTs) took place once these lower prices had been realized. These dynamics of investment in natural gas-fired units have not been identified before in literature that explores investment decisions in either regulated or restructured power systems (e.g. Bushnell and Ishii, 2007; Hill, 2016).

Finally, we study the planned and actual expansion at the resource level, but disaggregated by individual LSE. Figure 3 indicates that, in contrast to the aggregate results, there is considerable heterogeneity across the LSEs in the relationship between planned and actual resources procured. This finding supports the initial motivation for and research questions framed at the beginning of this paper. Several LSEs procured less capacity than their original plans (Avista, PugetSound, Seattle, and PNM), possibly due to lower than anticipated load growth rates over this period (Carvallo et al., 2016). However, the timing of procurement was not consistently different. Avista and PNM actually expedited resource procurement compared to their planned expansion, while Seattle and PugetSound did not change their expected timing.

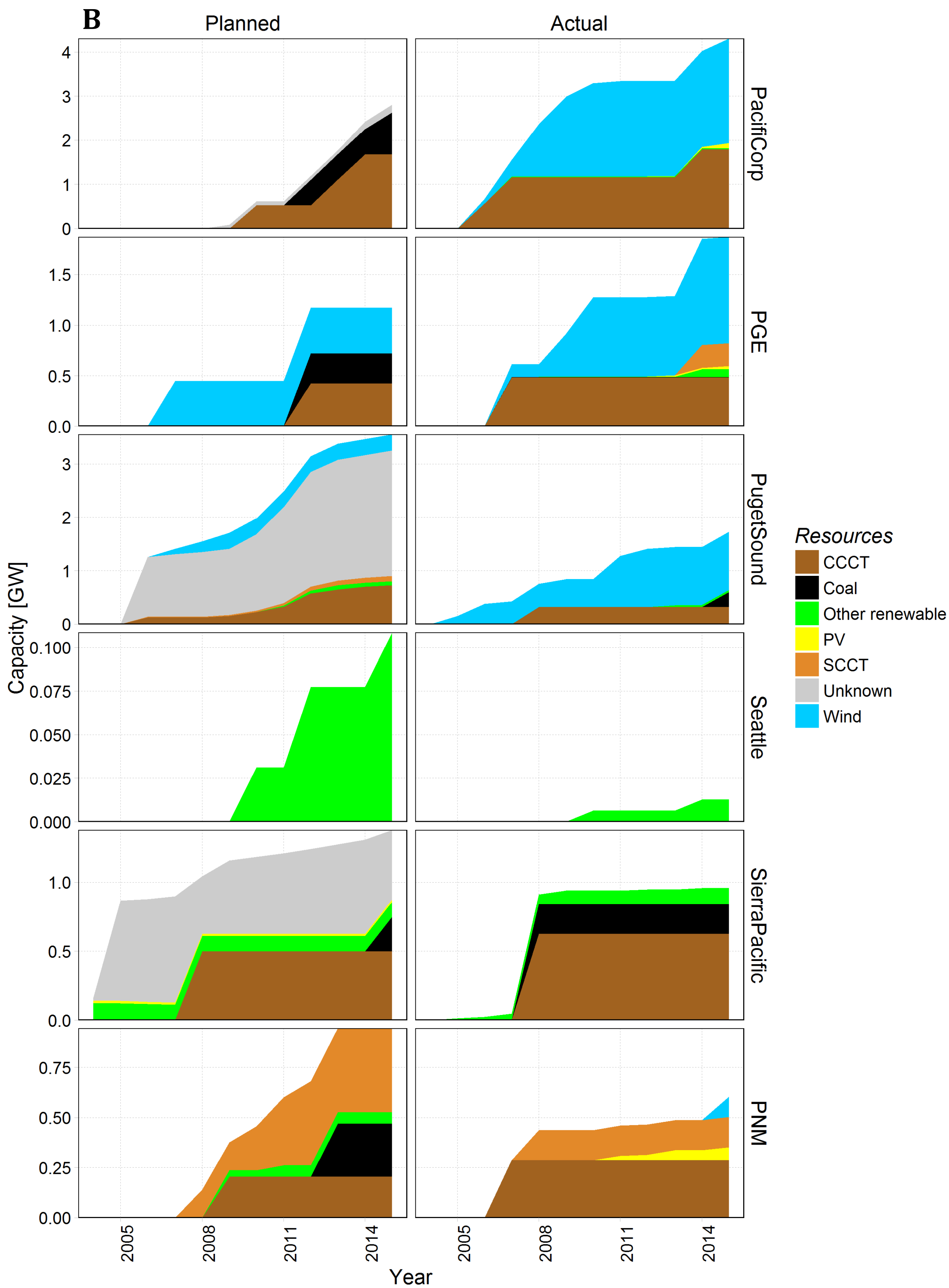
Another group of LSEs procured more resources than originally planned[11] (Idaho, PacifiCorp, and PGE). Much larger than anticipated procurement of wind is a common trait for these three cases. Idaho and PGE had planned for wind deployment, but procured between 2-3 times more than was originally planned. PacifiCorp had not planned for any wind in its 2004 plan, but more than half of its procured nameplate capacity included wind generation. In general, most of the LSEs that had planned to use wind as a future resource ended up procuring more than their originally planned amounts.

Finally, a third group of LSEs were relatively consistent in their actual expansion composition and timing compared to their plans (LADWP, SierraPacific, NV Power, and COPSC). For these LSEs, the largest difference between planning and procurement involved substituting planned coal units for natural gas-fired CCCT units along with minor changes in the timing of resource deployment.

[11] NW is excluded because they do not report a preferred portfolio in their 2004 IRP.



CCCT: Combined-cycle combustion turbine; SCCT: Simple-cycle combustion turbine; PV: Photovoltaic panel



CCCT: Combined-cycle combustion turbine; SCCT: Simple-cycle combustion turbine; PV: Photovoltaic panel

Figure 3. Total incremental installed and planned capacity for selected LSEs (panels A and B), split by resource type.

4 Case studies

4.1 Case study selection criteria

The selection of LSEs for the case studies is based on the following criteria:

- Select one LSE from each of the three groups identified in the previous chapter, that is, one LSE that procured *less* resources than originally planned; one LSE that procured *more* resources than planned; and one LSE whose procurement roughly matches what was planned in terms of capacity.
- The general availability of regulatory filings related to planning and procurement.

Avista (filing in Idaho and Washington) is selected as an example of an LSE that procured a lesser quantity of resources compared to its plan. Idaho Power (filing in Idaho) is selected as an example of a utility procuring more resources than originally planned. Finally, Sierra Pacific (filing in Nevada) was selected as an example of equivalence in planned and procured capacity. In the following section, we delve into each utility/jurisdiction case study to understand how their original plan and subsequent filings compared to actual procurement.

The case studies are both suggested, and made possible, by the availability of successive IRPs and other planning documentation for individual LSEs and the corresponding dockets in their regulating utilities commissions. The IRP documents generally provide sufficient information on the composition and evolution of the companies' generation assets and power purchases and contracts, and how the action plans for a given IRP are adapted over time as new information becomes available and circumstances change. For some LSEs, the available procurement documentation refers to prior planning processes to explain divergences or coincidences. We use both sources when available or just trace successive IRPs in the cases where procurement decisions were not explicitly discussed.

4.2 Case study analysis framework

U.S. utilities usually employ three methods for their resource procurement, based on two ownership strategies (Kreycik et al., 2011). Utilities may choose to build and own an electricity generation unit within their service territory. If approved by regulators, the investment, fuel, and operational costs of these assets is incorporated into their rate base and recovered via customer tariffs. Alternatively, utilities can contract resources with third parties. Within contracting modes, the two most common methods are competitive procurement and bilateral contract negotiations. A request for proposals (RFPs) is the typical instrument employed in competitive solicitations. The main objective of an RFP process is to procure least-cost electricity by receiving multiple offers from competing bidders. Its main drawbacks are usually the administrative costs and the uncertainty in timing for resource contracting, which creates a barrier for developers and investors. Bilateral contracts are more predictable than RFPs, but regulators may not guarantee full cost recovery for this mode of procurement (Kreycik et al., 2011). We use this framework for resource procurement to identify and track the different modes of acquisition in the case studies.

There are two overall dimensions that we use to frame the case studies and structure our analysis:

A. How an LSE's preferred portfolio and procurement actions change over time as a result of changes in load forecasts, i.e., changes in the *magnitude* (in MW and/or MWh) of planned and procured supply[12]. We are interested in finding evidence on how the level and timing of changes in load forecast had or did not have an effect on procurement (see Table 2 for a summary of results)
B. How the mix of resources in the planned and implemented portfolios - i.e., proportions of coal, gas, wind, etc. - changes over time as a result of changes in relative costs, regulations, issues with contract implementation, etc., i.e., changes in the *composition* of the portfolio (see Table 3 for a summary of results)

In analyzing these two dimensions, we focus primarily on how uncertainty affects the procurement process and how the information flow from planning to procurement relates to the management of this uncertainty. Each case study starts with a summary of the planning rules for the corresponding jurisdiction, followed by a description of procurement rules if they are explicit. We then quantitatively compare planning and procurement by resource type, timing, and contracting mode. The case study continues with a detailed description of the "original" plan (see Table 1) and an account of its evolution through the regulatory record.

[12] Other sources for changes in magnitude are changes in plant retirement schedules and effective implementation of DSM strategies. However, these two have been shown to be less relevant than load forecasts as source of deviations (Carvallo et al., 2016).

Table 2. Summary of changes in magnitude of resource portfolios.

		(A) *Magnitude*	
	Overview	**How changes in load affected procurement decisions**	**How changes in load did not affect procurement decisions**
Idaho	Actual procurement levels above planned levels; timing is similar	The 2009 IRP load forecast projected lower growth in planning period out-years due to economic conditions.	The 2008 IRP update projected lower load growth than the 2006 IRP, but IPC nevertheless projected near-term energy and peak deficits, possibly due to contracting and implementation delays.
Avista	Actual procurement levels below planned levels; earlier deployment	Natural gas acquisition of around 275MW planned for 2010-2011 pushed back to 2019.	Following 2005 IRP, actual load growth was consistently lower than forecasts, but for the most part Avista continued to project near-term rebounding of growth, and therefore continued to plan for corresponding procurement levels.
Sierra	Planning and procurement timing and levels are similar.	Potential changes in load due to large industrial customers' departure from the service area prompted strategies to retain these customers. These had an impact on resource acquisition choices.	Generally, no adjustment in the 2004 IRP and subsequent amendments and IRPs. The 2010 IRP mentions no need for new capacity given the economic downturn.

Table 3. Summary of changes in composition of resource portfolios.

		(B) *Composition*		
	Overview	**Effect of cost changes**	**Effect of contractual issues**	**Effect of regulatory changes**
Idaho	Very similar choice of resources and contracting mode (owned and contracted procurement similar to planned). Only difference is a coal to natural gas switch in 2011.	Change in estimated costs resulted in large shift from coal planned in the 2006 IRP to natural gas in the 2008 Update; addition of Demand Side Management (DSM) resources in the 2009 IRP relative-to-previously-planned addressed a proportion of projected deficits	Property rights and other issues resulted in delays in major transmission upgrade; water rights issues resulted in delay of Shoshone Falls hydro upgrade; implementation and contracting problems resulted in delays and/or reduction in wind acquisition and geothermal; lack of industrial customer demand resulted in removal of planned CHP	Energy policy/ regulatory changes did not seem to have major effects, but as just noted compliance with existing land- and water-use regulations resulted in major delays
Avista	Planned for owned resources, but procured through contracts only. Procured mix is high in natural gas and lower in wind.	Coal acquisitions planned in 2005 IRP had by 2007 IRP been changed to natural gas as a result of changing relative costs; by the 2007 IRP, increases in wind costs following 2006 passage of Renewable Portfolio Standards (RPS) in Washington state resulted in decrease in planned wind purchases; in 2011, Avista projected that essentially all projected load growth could be met by demand-side rather than supply-side resources until 2019-2020.	Not exactly, but subsequent to 2005 IRP market purchases were re-introduced into procurement plans to make up short-term deficits resulting from delay in acquisition of new gas resource	Washington state RPS resulted in planned increases in wind in the 2009 IRP
Sierra	Very similar resources and contracting mode, only exception is a coal PPA that was not planned for.	No mention of relative costs or fuel prices impacting procurement decisions. The only natural gas resources acquired in the period sought approval in 2005, years before gas prices actually declined.	No apparent adjustments between planning and procurement due to contractual issues.	Nevada state RPS changes in 2009 resulted in larger than expected procurement of renewable resources. New EE targets may have required less procurement of other resources.

4.3 Sierra Pacific – Nevada

4.3.1 Summary of IRP rules

In Nevada, resource planning rules are codified in section 704.9 of the Nevada Administrative Code (NAC). Sierra Power's first resource plan was filed "on July 1st, 1989 and every three years thereafter" (NAC 704.9208). The plan should assess resource requirements for the next 20 years. The utility is also required to file an action plan that includes an energy supply plan, both for the three years after the filing of the IRP (NAC 704.9482). "In its action plan, the utility shall specify all its actions that are to take place during the 3 years commencing with the year following the year in which the resource plan is filed" (NAC 704.9489.1). The energy supply plan is composed of a power procurement plan, a fuel procurement plan, and a risk management str1ategy. The Commission can approve or not approve the action plan applying a prudency standard for both the action plan as well as the energy supply plan included in it, but sometimes it may not be able to determine prudence at the time of the review.

The process continues with a progress report to be filed not before 15 but not after 21 months. The progress report must update on change of status for planned resources, status of conservation programs, deviations from the action plan and changes in costs and load forecast (NAC 704.9498). An amendment to the action plan is required when the utility "anticipates submitting an application for a permit to construct a utility facility […] which was not previously approved as part of the action plan" (NAC 704.9503.1(a)). In addition, an amendment must be filed when the utility commits to acquiring or contracting resources that were not in the approved action plan. Short term changes may require also for the utility to file an amendment to its energy supply plan. Amendments to the action plan shall be made pursuant to NAC 704.9503 must follow the guidelines in NAC 704.9516.

The approval and amendment process for IRP, action plans, and energy supply plans initially suggests that the Nevada PUC supports a very strong link between planning and procurement. The language suggests that approvals are made under a prudency standard equivalent to the one used for procurement in other jurisdictions. This partly explains the similarity in the timing, level, and type of resource acquired compared to the resource plan described in Section 3. Amendments may indicate deviations, but as stipulated in the Nevada Administrative Code they may be used to specify the terms of certain acquisitions that were originally planned for.

4.3.2 Comparison of planned and procured capacity

Following the methods described in Section 3, we compare Sierra's 2004 IRP preferred portfolio expansion against actual procurement decisions split by resource type and contracting mode (Figure 4)

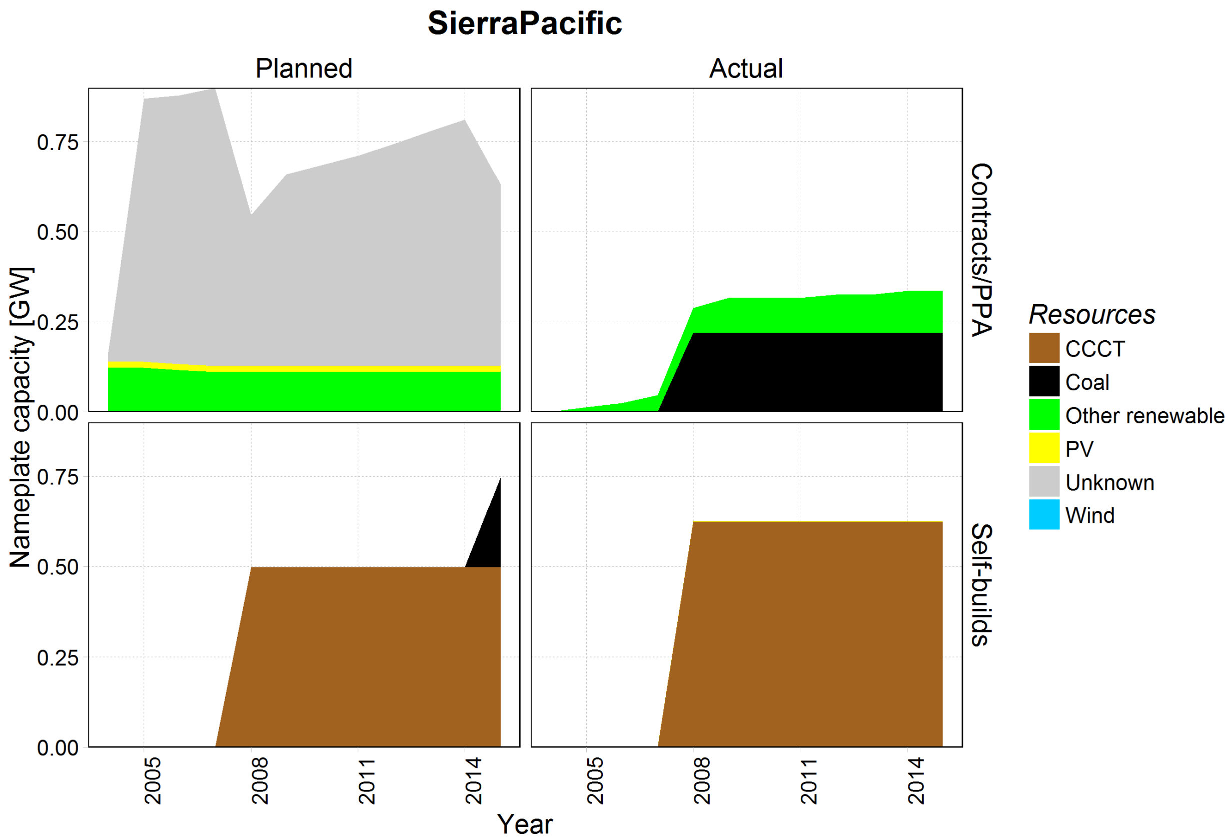


Figure 4. Comparison of planned and procured nameplate capacity: Sierra Pacific[13]

Sierra Pacific owned resource expansion was very similar as its planned expansion, which is consistent with the procurement approach outlined in subsection 4.3.1. Sierra had planned market purchases for around 500 MW, which turned out to be replaced by a coal PPA. Its actual renewable resource additions were very consistent with the original plan, perhaps as a consequence of a prevailing Renewable Portfolio Standard (RPS).

4.3.3 From planning to procurement

The 2001 energy crisis prompted the Nevada state government to strongly support less reliance on external market purchases for its electric utilities through the Nevada Energy Protection Plan. This is acknowledged in several introductory documents and is an important element of the 2004 IRP and subsequent plan strategies (Timney, 2015).

In its 2004 plan, Sierra expected its load obligations to grow from 1,914 MW in 2005 to 2,771 MW in 2024. A 500 MW CCCT plant to be located at Tracy in 2008 (ultimately commissioned that year) was the cornerstone of Sierra's planning strategy. The utility also proposed a 250 MW coal-fired unit in Valmy to

[13] Sierra Pacific included annual short term purchases that were not cumulative as part of their planned contracts. That explains why the upper left panel is not monotonically increasing, reflecting differing purchase decisions each year depending on their open position and strategy.

be built between 2011 and 2015, but this was not part of their Action Plan. Ownership of resources was preferred to provide price stability and ensure reliability to customers.

There were fourteen amendments to the original plan filed in July 2004, which covered the 2005-2024 period. As mentioned, Sierra Pacific is required to file amendments upon relevant changes on assumptions and economic conditions, but also to provide details and ask for approval of PPAs and other contracts. Using this particular feature of the Nevada regulation, we proceed to chronologically review the relevant amendments to action plans in order to identify relevant changes and adjustments. The first relevant change to the original 2004 plan came in the fourth amendment filed on December 23rd, 2004. This amendment sought approval for a coal based generation PPA. In its 2004 IRP, Sierra highlights uncertainty on the permanence of two large customers, whose departure from its system would have had a relevant impact on their load forecast. In this amendment, Sierra acknowledges the departure of one of these customers (Barrick Mining) and produces an updated load forecast. In this context, the PPA is signed as part of a compromise to prevent the other customer (Newmont Mining) from leaving Sierra's system. This customer will build a 203 MW coal-fired generation unit and sell its output to Sierra. Note that in its original Action Plan, Sierra did not recommend the construction of a coal-fired generating unit at that time (see p.6).

The transaction is justified by the benefits of having additional generation within Sierra's control area and by lessening its "dependence on volatile natural gas prices" (p.11). The amendment points to additional benefits of this plant due to avoidance of transmission congestion of imports and of curtailment of hydroelectricity due to adverse hydrological conditions, replicating arguments posed in the original plan. The economic evaluation shows important benefits to Sierra's customers of preventing the departure of the customer pursuant to NAC 704B.320[14]. It also highlights the large operational savings if natural gas prices were to rise above forecast levels. Finally, there were no changes in the planned resources due to the revised load forecast—which was reduced.

The eighth amendment was filed on August 1st, 2005. This amendment was required by the Nevada Commission as part of the approved stipulation for the 2004 IRP. The amendment sought approval for the construction of a 514 MW combined-cycle (CC) natural gas-fired plant at Sierra's Tracy Station in Nevada. Sierra argues that the plant is cost-effective, improves the reliability of its system due to their location within its control area, and is more flexible than other alternatives. The load forecast remains unchanged since an updated load forecast was included as part of the fourth amendment. Sierra did update its market fundamental analysis (for natural gas and electricity prices) and provided an updated economic assessment for the Tracy power plant in this amendment. These updates serve as inputs to a new set of eleven expansion plans that include this new CC, market purchases, and the option that the Newmont coal plant—part of the fourth amendment—would not be built. The least-cost portfolio includes the aforementioned 514 MW CC plant for deployment in 2008 and two 250 MW coal-fired plants for deployment in 2011.

[14] NAC 704B.320 is a rule that allows certain customers to choose their provider of electricity in Nevada.

The tenth amendment, filed on April 11th 2006, is also relevant for planning purposes. This amendment sought approval of an increase in the budget for two DSM programs that Sierra needs to comply with efficiency goals mandated by Nevada state legislation (Assembly Bill 3 or AB3) that was unanticipated during the development of the 2004 IRP. Among others, the bill mandates the use of energy efficiency to meet renewable portfolio standard targets, requires that 50% of those credits come from the residential sector, and increased the energy efficiency requirements from 15% to 20%. Sierra aims to augment its DSM program to meet these new objectives.

We compare the new load and resources balance with the previous one filed in the fourth amendment. In this case, there are 18 MW less in existing resources, namely diesel generators due to unavailability. Planned supply side units are unchanged. There is also a significant reduction in planned purchases, roughly half of the purchases identified in the revised load and resources balance. Transmission capacity and its commitments are unchanged. System load is reduced by ~1.5% due to the impact of DSM programs that are treated as reduced load instead of a demand side resource.

The thirteenth amendment to the 2005-2024 IRP filed on July 14th, 2006 is the last relevant amendment to our analysis. In this amendment, Sierra applied for the approval to build two coal-fired supercritical 750 MW generation units to be installed in 2011 and 2013, respectively. In addition, it sought approval for the North/South Intertie, a new 500 kV transmission system to interconnect the Nevada Power and Sierra Pacific power systems. These new assets are part of the "Ely Energy Center", a joint venture between Sierra and Nevada Power Company. Initially, Sierra's share of the project was 20% or roughly 300 MW of coal-fired capacity. The application also sought approval to decommission (or replace) diesel units and implement minor upgrades to existing units. Finally, the application includes updated load, fuel price, and electricity price forecasts and a revised Energy Supply Plan. The peak demand forecast is roughly 10% lower compared to the forecast filed as part of the fourth amendment. Unfortunately, fuel and electricity prices were redacted in this amendment and cannot be compared against the previous values.

The resources planned as part of this amendment are different than the current load and resources table from the fourth amendment. The Tracy CCCT and Newmont coal plants do not change in time of deployment or capacity. However, the original 250 MW coal plant to be deployed in 2015 is brought ahead in two 150 MW blocks to be deployed in 2012 and 2013, respectively. The original additional 250 MW coal plant to be deployed in 2021 is now replaced by two 100 MW combustion turbines planned for 2016 and 2018, respectively.

We found no discussion in the documents that compares this new preferred portfolio and the original portfolio. The amendment essentially replicates the IRP exercise by designing and comparing twelve portfolios against each other, but not against past alternatives. The new resource plans are designed to reduce market purchase dependence and increase reliability through installation of owned generation within Sierra's operating territory. We can infer that the differences between the previous plan and the new one put forth in this amendment are informed by that directive, but Sierra provides no justification for the new plan.

By the time the 2007 IRP was issued, the Newmont and Tracy plants were under construction. The peak load forecast for the 2007 plan was on average ~15% less than the 2004 plan. The 2010 IRP indicates that "with the decline in loads caused by the economic downturn, completion of the Tracy Combined Cycle unit ("Tracy") and acquisition of the output of the Newmont coal plant in 2008 ("Newmont"), Sierra now has sufficient Company-owned and/or controlled generation to meet most of its customers' near and mid-term needs" (Summary p.5). The peak load forecast in the 2010 IRP was ~15% lower than the 2007 forecast and was expected to remain flat during the first few years of the plan.

Finally, in 2009, Nevada passed new RPS targets as part of SB 358 that required Sierra to increase the proportion of renewable energy in their mix. This increase in procured renewable energy is shown in the right panel in Figure 4, but it reached levels closer to those originally planned in the 2004 IRP.
In summary, Sierra's major procurement decisions during the period were the Newmont 203 MW coal plant transaction and the owned 514 MT Tracy natural gas plant. The Newmont transaction was signed to prevent a major customer from departing Sierra's service area and a similar strategy with Barrick Mining failed. Even before the 2008 crisis hit, load forecasts were consistently over-estimating actual load and were rarely adjusted downwards. These forecasts supported plans for large coal plant units that were indefinitely postponed after the 2008/2009 crisis.

4.4 Idaho Power – Idaho

4.4.1 Summary of IRP rules

Idaho Power operates in Idaho and Oregon under the jurisdiction of those states' public utilities commissions. In Idaho, rules and regulations governing integrated resource planning stem from Idaho Public Utilities Commission (IPUC) Order No. 22299, issued in January 1989, which addressed among other topics utilities' treatment of energy conservation and efficiency in their resource planning. It stated that "Least-Cost" and "Integrated Resource" planning were essentially interchangeable terms, and reviewed key points that had been made by Idaho Power, the IPUC staff, and other stakeholders. Among the IPUC findings in this order was that consideration of utilities' treatment of efficiency and conservation by regulators and the public was essentially impossible without understanding the content of such planning. Consequently, the IPUC required each utility under its jurisdiction to begin submitting more comprehensive and detailed resource planning reports for Commission review, and to adopt a 20-year horizon in the analyses.

Order No. 29189 (February 2003) discussed the status of the company's planning process in light of Order No. 22299 and broader stakeholder input. The IPUC concluded that to fully comply with No. 22299, improvements had to be made to future Idaho Power IRPs. The IPUC instructed Idaho Power to increase its efforts to include the public in its planning process and avoid regarding that the IRP process as "simply an academic or regulatory exercise". The utility was directed to treat the IRP as an "actual planning document" for meeting resource needs and contract obligations, and to improve its analysis of demand-side options.

The Regulatory Assistance Project (RAP) released a summary of resource planning requirements, processes, and outcomes in a number of states including Idaho (RAP, 2005). Among RAP's findings was that the Idaho's IRP process was ongoing and entailed participation of IPUC staff in drafting resource plans, rather than external IPUC monitoring of a utilities planning process. RAP also found that the IPUC judged the merits of resource acquisitions subsequent to the submission of an IRP solely in terms of conditions at the time of the acquisition, not in comparison to the IRP. RAP also found that companies had to justify significant deviations from the plan as well as, when relevant, the utility not adapting acquisitions to reflect changing circumstances.

IPC filed its 2006 IRP with the IPUC in September 2006 (and a revision with corrections the following month). Following the submission and review of stakeholder comments, and a review and discussion by the Commission's staff, the IPUC accepted the IRP in March 2007 (IPUC, 2007). It noted that "Our acceptance of the 2006 IRP should not be interpreted as an endorsement of any particular element of the plan, nor does it constitute approval of any resource acquisition or proposed action contained in the plan."

IPC's Oregon operations are subject to provisions of the Oregon Public Utilities Commission's (OPUC's) Order No. 89-507 from 1989, which instructed energy utilities in the state to conduct least-cost planning. Key provisions included the consideration of both demand-side and supply-side resources, the use of a 20-year planning horizon, the inclusion of uncertainty analysis, and that companies' resource portfolios be "...least-cost to the utility and its ratepayers consistent with the long-run public interest," and consistent with Oregon's state energy policies. Procedurally, the Order required that resource plans be submitted to the OPUC every two years for review to confirm compliance with the Order (and further work if needed), but stated that once compliance was verified, the OPUC would "acknowledge"—rather than "approve" the plan. The Order specifically stipulated that the utilities retained final authority and responsibility for their decisions. The provisions of Order 89-507 were reaffirmed in OPUC's Order No. 03-389 in 2003.[15]

IPC filed its 2006 IRP with the OPUC in October 2006. Following a period of public comment, and a review by its staff, the Commission formally acknowledged the IRP in September 2007 (OPUC, 2007).

4.4.2 Comparison of planned and procured capacity

Following the methods described in Section 3, we compare Idaho Power's 2006 IRP preferred portfolio expansion against actual procurement decisions split by resource type and contracting mode (see Figure 5)

[15] Subsequent to IPC's filing of its 2006 IRP, the OPUC issued Order 07-002 in 2007 (corrected in 07--047), summarizing the findings of a proceeding to re-visit and as needed update 89-507. The provisions of the 1989 order were, overall, maintained, with some amendments.

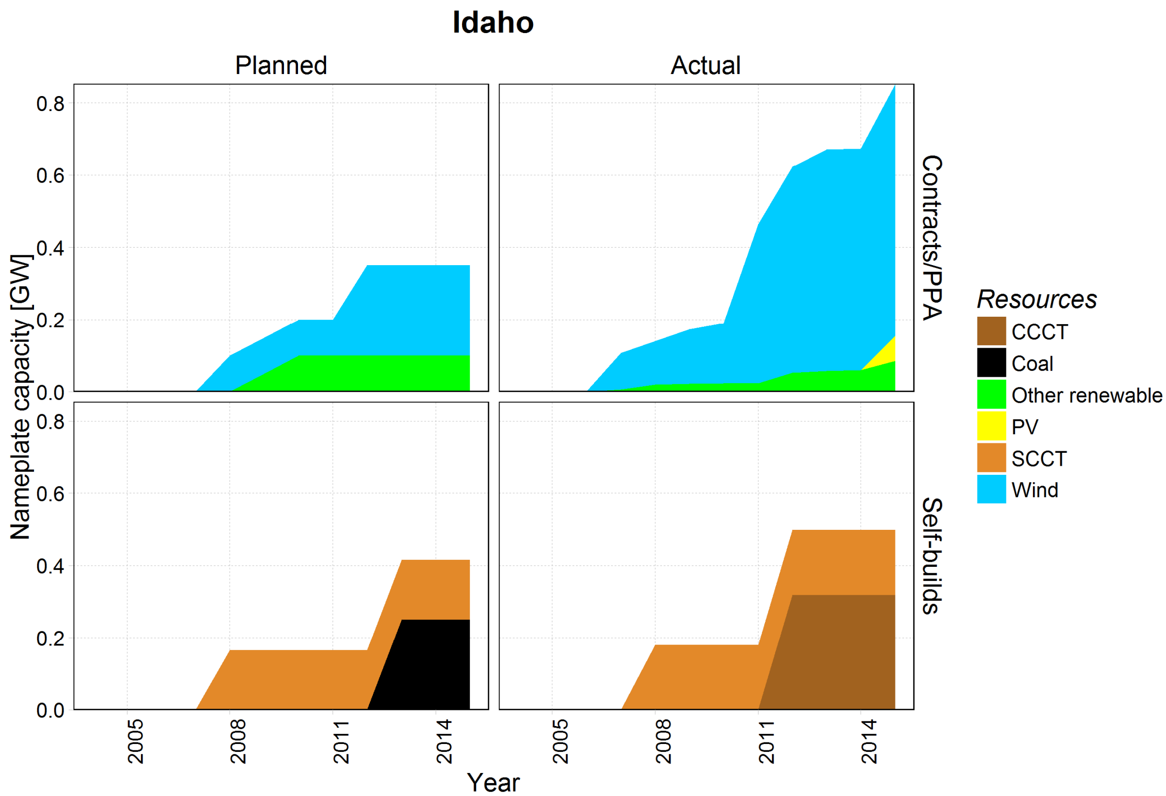


Figure 5. Comparison of planned and procured nameplate capacity: Idaho Power

Idaho Power replaced its planned coal plant with a natural gas-fired CCCT procured roughly around the same time as the originally planned coal plant. Overall, Idaho Power's owned resource procurement level was very similar to its 2006 plan. In contrast, PPAs for wind were three times larger than originally anticipated.

4.4.3 From planning to procurement

The primary resource asset acquisition components of the 2006 preferred portfolio were a 250 MW increase in coal-fired capacity by 2013, through either expansion of existing coal facilities or a new facility, and a 225 MW upgrade of the McNary Boise transmission line (subsequently renamed Boardman-to-Hemingway), with the new capacity to be available in 2012. IPC also planned for a 62 MW expansion of its Shoshone Falls hydro facility, to be completed in 2010. In addition, several PPAs were planned: 100 MW of wind by 2007 (from an RFP that had been issued in 2005), with an additional 150 MW by 2012; up to 100 MW of geothermal by 2009, and 50 MW of CHP by 2010. Overall, the 2006 preferred portfolio comprised an addition of 825 MW nameplate capacity by 2013, and 1,585 MW by 2023. The company stated that anticipated new customer growth was the primary driver of these resource acquisitions.

IPC reported in its 2008 IRP Update that re-analysis found the coal resource to be uneconomic compared with natural gas when transmission costs were included. (This finding was robust across all levels of a potential carbon "adder.") In 2008, Idaho Power issued a buy-or-build RFP for 250-600 MW of dispatchable, physically-delivered firm or unit contingent energy, with the range reflecting uncertainty regarding additional load from large industrial customers. In the 2008 Update portfolio analysis, 250 MW of natural gas (a new CCCT plant in Southeast Idaho) was considered, and substituted for the coal generation. In addition, the Update reported that an RFP had been issued in January 2008 for 50 MW of geothermal, to come online by 2011, to "offset deficits resulting from PURPA contract terminations." This geothermal addition was the only net increase in the updated portfolio relative to the 2006 portfolio; in the update, an incremental 875 MW nameplate capacity by 2012 was planned, and 1,635 MW by 2023.

In its 2008 IRP update, IPC also reported that the IPUC had approved a PPA for 101 MW of wind and that this resource (from the Elkhorn facility in Oregon) had come online. The same year, it accepted a bid for 45.5 MW of geothermal at Neal Hot Springs, with 13 MW of this approved in January 2008. It also reported that it would shortly begin negotiations for the remaining 32.5 MW, and that the CHP resource was being worked on.

Revised load forecasts prepared for the 2008 Update projected lower growth rates for both energy and peak demand when compared to the 2006 forecasts. IPC reported that this was due to three factors: (1) greater-than-anticipated savings from DSM programs; (2) the fact that, while DSM is treated as a supply resource in IRP plans, once programs are initiated they are considered "committed" and therefore are reflected in the load forecast itself; and (3) future energy price increases were projected to be greater-than-anticipated in the 2006 forecast. Nevertheless, the Update's surplus-deficit analysis—through 2013-2014—appeared to find greater near-term energy and peak deficits with existing and committed resource than were originally estimated in the 2006 IRP.

It is possible that this apparent discrepancy reflected problems with PURPA contracts that had emerged after the 2006 IRP. IPC's policy is to include in its IRP plans only PURPA contracts that have been approved and signed by the IPUC. In the 2008 Update, the company reported that of more than 250 MW of signed and approved contracts that had been included in the 2006 IRP, none had met their scheduled operational dates, "a few" were under construction, and 150 MW had been "delayed until 2010, or possibly indefinitely." It is not clear whether these previously committed 250 MW were removed from the anticipated resource mix in the 2008 projection, but if they were the result may have been the above-mentioned surplus-deficit discrepancy between the 2006 and 2008 analyses.
By the time of the 2009 IRP, the Danskin expansion that had been underway in the 2006 IRP was fully operational. In addition, a 300 MW CCCT (Langley Gulch) was underway, considered committed, and anticipated to come online in 2012. The Shoshone Falls hydro facility upgrade that the 2006 IRP had foreseen completed by 2010 was delayed to 2015 as a result of unanticipated delays in licensing approval and in the securing of water rights necessary for the project.

The 2009 IRP also reported that IPC issued RFPs, and received proposals, for the 150 MW wind resource planned for 2012, which was originally identified in the 2006 IRP. However, the evaluation process was delayed until later in the year due to the need for transmission analysis. Contract negotiations were underway by the end of 2009 and IPC expected to submit for IPUC approval in the first part of 2010.

IPC reported that it had determined that the 32.5 MW geothermal increment at Neal Springs (indicated in the 2008 update) would not be feasible within the contract terms, but that it had negotiated a contract for 20 MW from this site, which it submitted for IPUC approval at the end of that year. IPC also reported that it had found much less interest in the 50 MW combined heat and power resource than it had anticipated among its large industrial customers. Consequently, this specific resource was withdrawn from its list of committed resources pending further study.

The projected growth in average system load—indicated in the 2009 IRP—was lower than projected in the 2006 IRP primarily due to changing economic conditions. However, IPC's advisory group believed that the highest risk associated with the load forecast was for *greater*-than-historical growth rates. IPC projected deficits of energy during four months by 2014, and significant peak-hour deficits by 2012, with then-existing resources, with both deficits becoming quite severe by the end of the planning period (late 2020s). The addition of committed resources and new DSM substantially reduced these deficits, and the addition of all the resources in the 2009 IRP preferred portfolio essentially eliminated them.

In its 2011 IRP, IPC reported that the 150 MW RFP for wind generation "...did not ultimately result in the identification of a successful bidder." This was because an increase in PURPA wind development had driven the total cost of wind below the level at which the utility had estimated was required for cost-effectiveness, and this had in turn resulted in the IPUC lowering the allowable cost for the resource below IPC's cost-effectiveness threshold. It also reported that IPUC approved about 22 MW of generation from Neal Hot Springs, expected to be online in 2012, and that the Federal Energy Regulatory Commission (FERC) approved the 49 MW Shoshone Falls upgrade, which was expected to be completed in 2015.

IPC's analysis showed that with then existing and committed resources and planned DSM, peak load deficits could occur as early as 2015 followed by energy deficits in 2018—with both deficits becoming very severe by the end of the planning period (2030). These projected deficits were alleviated, but not eliminated with the assumption of new DSM programs. The deficits were eliminated with addition of the new resources in the 2011 preferred portfolio.

In its 2013 IRP, IPC reported that the 22 MW Neal Springs geothermal resource had become operational in 2012, and that it had requested and been granted by FERC a delay in the Shoshone Falls upgrade project, which would not be completed until 2019. The Boardman-to-Hemingway transmission upgrade originally foreseen in the 2006 IRP as providing new capacity in 2012 had not yet been completed and its operational date pushed back to 2018. It should be noted that the 2013 preferred portfolio also identified a substantial increase in demand response programs.

The following bulleted list is a summary of the resources planned to be procured by 2014 as originally identified in the 2006 IRP:

- The new coal resource was replaced by a CCCT facility, which entered operation in 2012.

- The Boardman-to-Hemingway transmission upgrade was delayed, and as of 2013, was planned for completion in 2018.
- The Shoshone Falls hydro upgrade projected for completion in 2010 was delayed until 2015.
- A PPA for 100 MW of wind was implemented on schedule in 2007.
- An additional 150 MW of wind planned for 2012 did not materialize due to (according to IPC) a "surge" in Idaho PURPA wind development.
- 35 MW of geothermal were ultimately procured (instead of a planned 100 MW)
- 50MW of CHP was withdrawn because of an unexpectedly low level of interest among the company's large industrial customers.

Over the 2006-2014 time period, IPC's load forecasts were revised downward, due to the economic recession that began in 2008. However, it is important to note that IPC's IRPs do not seem to explicitly tie lower load growth with any associated changes to planned procurement actions. Instead, as discussed above, a number of factors including technical, economic, and other factors are cited as reasons for not procuring resources that were originally identified in the 2006 preferred portfolio.

4.5 Avista – Washington/Idaho

4.5.1 Summary of IRP rules

As a supplier of electricity, Avista operates under the authority of both the Idaho Public Utilities Commission and the Washington Utilities and Transportation Commission (WUTC)[16]. The Idaho regulatory environment for IRP was described in subsection 4.4.1

In Washington, Avista is subject to the provisions of Section 480-100-238, "Integrated Resource Planning" by electric utilities, of the Washington Administrative Code (WAC).[17] Among its key elements are the requirement to develop and submit IRPs to the WUTC every two years, to include both demand-side and supply-side resources for meeting projected load requirements, as well as both "conventional and non-conventional generating technologies," and to perform an analysis determining "lowest reasonable cost" of meeting its commitments that takes account of factors including direct and environmental costs including those associated with carbon dioxide emissions, various sources of risks, and applicable state and federal regulations and policies. The Section also requires regulated utilities to report to the WUTC progress on IRP implementation as well as to submit work plans for "informal commission review."

As a matter of process, the WUTC neither approves nor disapproves integrated resource plans submitted by utilities under its jurisdiction. Instead, if it finds that a particular IRP fulfills the state's statutory requirements with respect to its contents, it "acknowledges" the plan (WA UTC, 2006, 2005). Avista's 2005 IRP was acknowledged by the WUTC (Steve Johnson, 2017)

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[16] Avista also provides natural gas service in Oregon.

[17] See: http://app.leg.wa.gov/WAC/default.aspx?cite=480-100-238

4.5.2 Comparison of planned and procured capacity

Following the methods described in Section 3, we compare Avista's 2005 IRP preferred portfolio expansion against actual procurement decisions split by resource type and contracting mode (Figure 6)

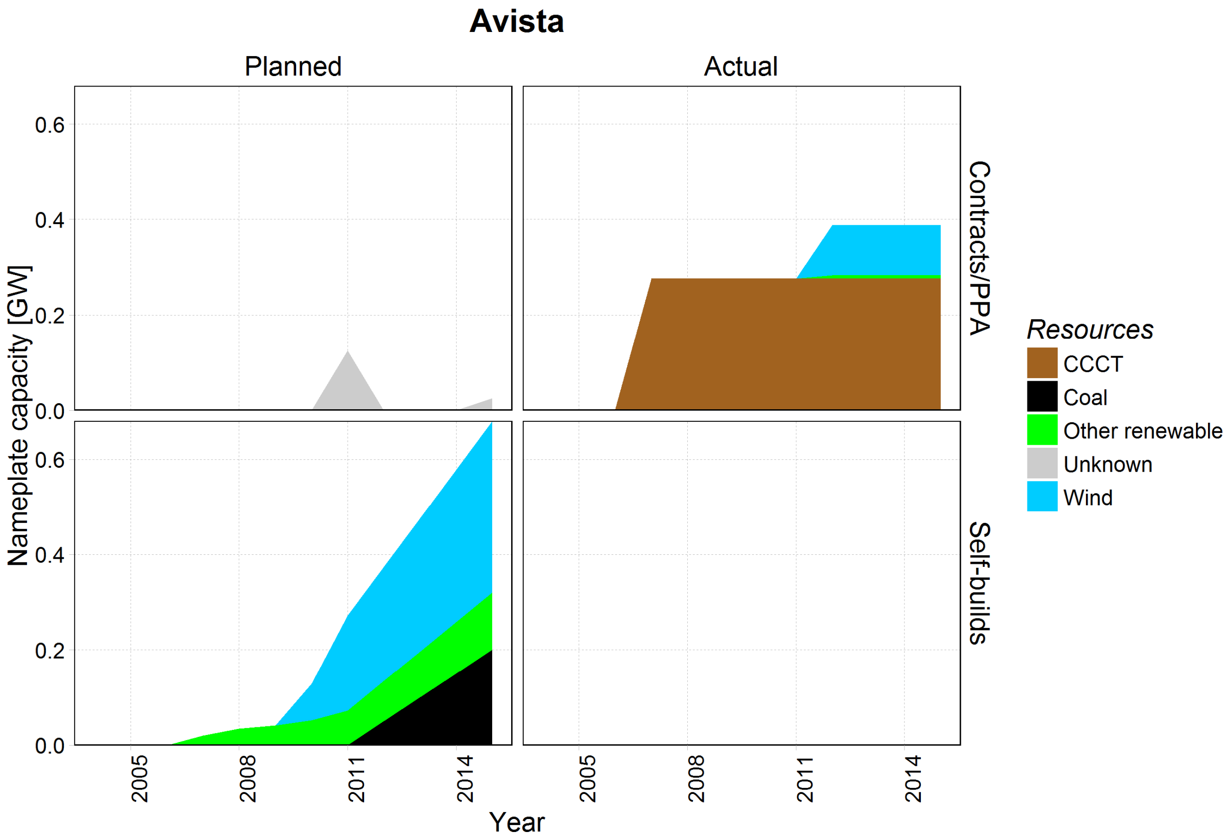

Figure 6. Comparison of planned and procured nameplate capacity: Avista

Avista had planned an expansion of ~650 MW using utility-owned wind, other renewable, and coal resources. Its procurement level was two thirds of that capacity, but was fully contracted instead of self-built. A natural gas-fired CCCT replaced coal and part of the wind resource as the preferred resource.

4.5.3 From planning to procurement

Avista's 2005 IRP Preferred Resource Strategy (PRS) emphasized renewables and efficiency as well as upgrades to existing plants, which the company projected together could meet more than fifty percent of its anticipated load growth.[18] However, it also estimated that these resources could meet only about two-thirds of its total capacity needs, and about one-third of its total energy needs, by 2016. It thus included a substantial increase in its coal generation capacity in the 2005 PRS. By 2014, the PRS would have added 350 MW of wind,[19] 250 MW of coal, 52 MW from plant upgrades, 40 MW of other

[18] Avista's documents use the term "conservation" synonymously with the more common "efficiency."

[19] In some of its tables, Avista reports wind in terms of its contribution to meeting system peak, which it estimates as twenty-five percent of capacity. In others, it reports nameplate capacity; the figures given here are the latter.

renewable resources, and about 20 MW of new efficiency savings, for a 2014 total of 712 MW in new resources, slightly more than a one-third increase over what Avista projected would be its existing resource capacity in that year.[20] The PRS also included 125 MW of market purchases in 2011.

Regarding the large increase in wind resources, Avista stated that "Though aggressive, [we] believe(s) it is possible to develop 400 MW of wind resources by 2016 and 650 MW by 2026 by pursuing three different wind resource strategies." For the 2026 goal, these were a) Acquiring 250 MW of Northwest regional wind generation (roughly Avista's pro-rated share based on loads); b) Developing 150 MW wind "capability" within Avista's service territory; c) Assuming that 250 MW would be available from outside the Northwest (e.g., Montana and/or Wyoming).[21]

By the time of Avista's 2007 IRP, the company reported that the costs of wind had increased more than fifty percent since 2005, in part due - according to the company - to increased demand for wind resources resulting from states' RPS requirements, in particular Washington's Initiative 937 (the "Energy Independence Act"), approved in November 2006. Wind additions planned for completion by 2014 were reduced from 350 MW in 2005's PRS to 100 MW in 2007's, and other renewables from 40 MW to 35 MW. Avista stated that to maintain RPS compliance, it would consider other options including purchasing renewable energy credits (RECs).

Moreover, while the cost of natural gas generation had increased relative to that of coal between the 2003 and 2005 IRPs, conditions had changed by 2007: Relative cost increases for gas had moderated, and in addition the new Washington state requirements precluded the consideration of coal as a long-term supply option in the 2007 analysis.[22] Avista therefore emphasized natural gas generation in its 2007 PRS, planning a new 280 MW CCCT plant to enter service in 2011. However, after the company had completed its analysis for the 2007 IRP but before actual filing of the plan, it learned of the availability of 275 MW of natural gas capacity under a contract with the Lancaster facility in central Idaho starting in 2010.[23] (The Lancaster plant was held by a subsidiary of Avista Energy, the parent company of Avista Utilities, which we are analyzing here.) Recalling that the 2005 IRP foresaw new coal generation available in 2012, and relied on 125 MW of market purchases in 2011 to meet the expected temporary deficit, the 2011 availability of this gas resource allowed the company to avoid having to rely on the market, and to obtain the output under a contract rather than from a new build[24].

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[20] Table 7.5, p. 7-34, Avista 2005 IRP main document, and "Resource Strategy Detail" table, p. D-2, Appendix Vol. 2.

[21] The 2005 IRP refers in several places to "build-out" of wind capacity. However, the discussion of wind in Chapters 5 and 7 (including the "strategies" stated here) indicate that only the in-service territory addition would entail construction of new company-owned generation assets. Thus, according to the relative proportions of the three sources cited here, slightly less than one-quarter was planned as actual new build by Avista, with the remainder to be acquired through PPAs or contracts.

[22] Specifically, Section 80.80 of the Revised Code of Washington (RCW) placed a five-year limit on power purchase agreements involving coal.

[23] Avista Energy, a unit of the company, was sold in 2007; it held a PPA for output from the Lancaster plant that was transferred to another company, Coral Energy, and the parent company apparently had not anticipated that it would be able obtain the Lancaster output from this entity.

[24] That is, the output from Lancaster in effect replaced the generic coal and market purchase resources that had been included in teh 2005 IRP.

In addition, 2005 had seen an increase (over the 2003 IRP) in planned DSM resulting from an increase in its cost-effectiveness relative to supply options. By 2007, Avista's experience with DSM programs resulted in even greater efficiency potential being identified. In addition, the utility began taking account of other features of demand-side measures, including risk reduction and T&D savings. The 2007 PRS included 56 MW of savings from existing and new efficiency measures by 2014. This was an increase over the 49 MW in the 2005 PRS, of which about 20 MW had been incremental, that is, above and beyond continuing savings from programs already in place as of 2005.

In the 2009 IRP, Avista again shifted its PRS in response to changing conditions, in particular again expanding its planned acquisition of wind power, in order to meet states' RPS requirements, especially in Washington; 2007's planned 100 MW of wind in 2014 was increased to 150 MW, and accelerated to 2012.[25] New non-wind renewable resources were removed from the 2009 PRS. In addition, it pushed back the acquisition of a new natural gas plant (included in the 2007 IRP PRS) to 2019, because of a lower load forecast and a decision to fill a short term deficit through market purchases instead. Savings from new and existing demand-side programs were included in the 2009 PRS as reaching the equivalent of 62 MW by 2014. This was an increase over the 49 MW – with 20 MW incremental as defined in the previous paragraph - in the 2005 plan.

In its 2011 IRP, Avista reported that with its then-existing resources, supply-side resource additions already underway, and increased energy efficiency savings, it would be able to meet almost all of its capacity requirements until 2019 and energy requirements until 2020. It projected a small MW deficit of a few years duration in its preferred portfolio prior to those years, but decided to address those through purchases rather than acquiring new long-term capacity in advance.[26] It reduced its planned 2012 acquisition of wind from 150 to 120 MW, which it was in the process of completing through a 2011 RFP for a PPA, which selected the Palouse Wind Project in southwest Washington.[27] The company also estimated that almost one-half of its projected load growth could be met by energy efficiency, projected savings from which in the 2011 PRS were about twenty-five percent greater than in the 2009. Avista's 2013 PRS differed from the 2011 in a number of ways. For the purpose of this analysis, however, the important element was that the Palouse Wind facility had entered commercial operation at the end of 2012, and Avista's 120 MW PPA with the facility had been implemented.

In summary, Avista's 2005 IRP Preferred Resource Strategy and its subsequent resource acquisitions went through repeated adaptation to significant changes in the economic, regulatory, and technical factors that determined the company's resource needs, mix, and costs. From a combination of renewables—especially wind—coal, and efficiency, and no new natural gas in the 2005 PRS, Avista's strategy changed in 2007 to no coal, less wind, and a significant amount of new gas generation capacity,

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[25] Avista's 2009 IRP analysis concluded that this additional wind resource was not cost-effective except for this RPS requirement.
[26] The short duration capacity gap is created by peak load growth but ends due to the expiration of a long-term off-system sale of capacity that expires prior to 2019.
[27] The company reported that it planned to complete this acquisition by the end of 2012 in order to take advantage of federal tax incentives.

reflecting new RPS requirements and decreased relative costs of gas generation. In 2009, it changed again, once again increasing its planned acquisition of wind for regulatory compliance, while delaying its planned new gas capacity in response to lower projected load growth. By 2011, Avista estimated that its existing resources and increased energy efficiency savings could essentially meet projected capacity requirements until 2019 and energy requirements until 2020. In 2013, the strategy was again adjusted, but in the present context the important development had to do with wind: Avista's 2005 plan of 350 MW new wind by 2014, which had been reduced to 100 MW in the 2007 PRS, increased to 150 MW in the 2009 PRS, and decreased again to 120 MW in the 2011 Plan, was ultimately implemented as a 120 MW PPA beginning at the end of 2012.

5 Discussion

This discussion section is organized into two subsections. First, we discuss findings regarding the assessment and management of uncertainty in planning and procurement practices found in the case studies. This discussion is followed by an analysis of the actual relationship between the planning and procurement processes, the pace of change in planning and procurement assumptions, and its impacts on the efficiency and efficacy of both processes.

5.1 Management of uncertainty in planning and procurement

One critical objective of resource planning is to evaluate uncertainty, as there are many alternative expansion pathways whose relative costs and benefits may change depending on variables that can be controlled and others that cannot. We do not find evidence in the regulatory record on how the scenarios and sensitivities analyzed in the resource planning process are employed to inform procurement decisions.

An examination of regulatory practices through case studies reveals a set of common planning challenges that utilities face in relation to resource procurement uncertainty. We classify uncertainty under two broad categories: (1) exogenous and (2) endogenous. Exogenous sources of uncertainty are variables over which the regulator and planners have little to no control, including, but not limited to the broader economy, fuel prices, and load growth. Endogenous sources of uncertainty are variables over which regulators or planners may have some control, such as changes in the regulatory environment (e.g., RPS targets) and adjustments in rules to make certain processes more efficient, effective, or both. See Wilkerson et al. (2014) for a more comprehensive analysis of variables involved in risk assessment in IRP.

5.1.1 Exogenous uncertainty: Load growth and DSM

Long-term industrial customer load is an exogenous variable whose uncertainty has in some cases compelled utilities to develop different adaptation strategies for risk management. Sierra Pacific reports significant efforts to prevent two very large industrial customers from leaving its service area and thereby affecting its load projections. State of Nevada regulations allow users with annual consumption of at least 1 MWa to choose their retail electricity provider. In the timeframe analyzed, Newmont and Barrick Mining filed petitions to exit Sierra Pacific's system under this regulation. In both cases, the firms aimed to supply their operations by generating power themselves. The utility developed amendments to its original 2004 IRP to sign PPAs with these firms to retain them as customers and also purchase the electricity production from their power plants. The Barrick agreement fell through and this customer left the service territory, but the Newmont transaction resulted in the procurement of 200 MW of coal-fired generation for use across the broader service territory.

These efforts by Sierra Pacific are an example of a strategy to address potential load reductions due to the possibility of customers departing the service territory. Idaho Power employed a strategy to address higher-than-expected actual load. In 2008, the utility issued a request for proposals (RFP) for a broad range (250 to 600 MW) of capacity. The breadth of this capacity request was justified in an effort to address an uncertain amount of additional load from large industrial customers.

Load growth uncertainty from industrial customers has been correlated with higher aggregate load forecast error for utilities (Carvallo et al., 2016). The case studies reported here are consistent with that finding and provide evidence of the actual strategies employed by utilities to cope with such challenges. These strategies are specific and employed on a case-by-case basis. In addition, the adjustment strategies that utilities carried out to manage uncertainty in their industrial load were not reported as part of the general strategies derived from load forecasting sensitivities (see Carvallo et al., 2016). This finding supports the idea that introducing customer-specific load growth risk management methods could benefit the resource planning process. However, their usefulness will depend on these new methods being effectively used to inform procurement decisions.

DSM regulations and programs exhibit both exogenous and endogenous uncertainty. On one hand, Sierra Pacific and Avista report that changes in the regulatory requirements for energy efficiency prompted the need to procure more demand side management resources. These unanticipated changes produced differences with respect to their originally filed plans. On the other hand, Idaho Power and Avista report that their implemented DSM programs achieved larger savings than anticipated and were quite cost-effective. These outcomes informed future planning processes by reducing the load to be met, as well as refining the methods used to assess the impacts of these programs. It is important to note that, in all cases, utilities are responding to mandates or regulatory targets to achieve certain levels of programmatic energy efficiency and demand response. While utilities report these are indeed least-cost resources, this finding suggests that the IRP process continues to be required in order to assure that demand side resources are considered equally when compared to supply side alternatives.

5.1.2 Endogenous uncertainty: contracting and regulatory changes

Contracts and regulatory change are the two sources of endogenous uncertainty discovered through our analysis of the case studies. As discussed earlier, RFPs are the main form of competitive bidding contracting used in electric utility procurement. Idaho Power and Sierra Pacific reported the need to adjust their plans as a response to RFP processes that had (1) no bidders or (2) delays for resources previously contracted through an RFP process. The latter issue seemed particularly prevalent with smaller developers, perhaps due to the difficulties in securing financing for their projects. Strengthening the requirements and design of RFP processes has helped to minimize these impacts in more recent planning processes (Tierney and Schatzki, 2009). Utilities included in this study also employed other contracting methods in addition to RFPs. For example, Avista reports extensive use of medium term (~1-3 years) market purchases to cover deficit positions in their supply. In the case of regulatory and policy change, utilities in this study reported that RPS target adjustments forced them to continually revise their planning and procurement strategies. Avista specifically reported how the joint impact of RPS regulations in different states caused the costs of wind power to raise significantly above what was originally expected, which prompted them to revisit their least-cost procurement strategy. This joint effect of state-level regulations was not captured in the planning process for the three utilities analyzed in case studies and still remains a challenge. Other regulatory uncertainties facing the utilities include the future availability of the Production Tax Credit for eligible renewable resources and new targets for energy efficiency and demand response. There is evidence that utilities assess the risk of new targets and regulations in their IRPs (e.g. for carbon regulation, see Barbose et al., (2009)), but we did not confirm whether the assessments and strategies are used for procurement decisions.

5.1.3 Lessons for planning and procurement uncertainty management

We find that exogenous sources of uncertainty tend to have larger impact on the magnitude of procured capacity, but that endogenous sources have a larger impact on portfolio composition. Changes in load forecast and subsequent adaptation strategies informed levels of procurement that were lower than planned in the case of Avista and that cancelled projects in the case of Sierra Pacific. In contrast, DSM and RPS regulations forced changes in the procured resource mix. For example, Avista and Sierra Pacific reported adjustments in procurement compared to planning due to changes in RPS targets that resulted in shifts to wind capacity acquisitions that were not originally planned. In addition, Idaho Power reported the impact of additional DSM resources in displacing supply-side options. This finding suggests that regulators may have significant influence on the composition of procured resources by employing regulatory instruments, but little influence on the capacity of procured resources whose source of uncertainty is predominantly exogenous.

The rules governing integrated resource planning at the time the three case-study plans were created required sensitivity, risk, and uncertainty analysis, and the utilities were judged by the regulators to have met this requirement. At the same time, in these examples, the IRP analyses were based upon the information available at the time the plans were formulated, and as we have seen changing factors – both exogenous and endogenous – resulting in changed conditions for specific procurement decisions even within the two-year IRP planning cycle. As discussed earlier, the utilities responded to these changes in “real time” but, depending on their magnitudes, the IRP sensitivity, risk, and uncertainty analyses did not necessarily directly or specifically inform the procurement decisions.

5.2 The connection between planning and procurement.

The degree of connection between planning and procurement varied significantly among the case studies. Sierra Pacific reflects the spirit of the Nevada state regulations by connecting the planning and procurement process through the IRP amendment procedures. In this specific example, the similarity between planning and procurement outcomes attests to the impact of this regulatory design. As reported by one stakeholder: "This is largely, I believe, because a prudency determination in an 3-year action plan is made based on presented budgets and timelines, and Sierra [Pacific] has strong incentives to stick to them to recover costs."

In contrast, regulatory rules in Idaho, Washington, and Oregon explicitly state that IRPs are not "operational" plans; they are required to analyze generic rather than individual resources and the utilities are expected to explain deviations from the plans as appropriate in procurement cases. In these jurisdictions, explanations for deviations include the filing of intra-planning cycle updates to their plans, and account, at least informally through dialogue in specific procurement cases. These explanations of planning deviations loosely connect the IRP to procurement process, if any, and help regulators assess proposals to formally procure new resources. This loose relationship between planning and procurement is more prevalent across jurisdictions that employ IRP as a regulatory tool as opposed to the approach followed in Nevada that formally connects these two processes.

Utilities updated their plans in response to changes in their regulatory environment, near-term load growth expectations, and, to a lesser extent, fuel prices. Our analysis shows that most if not all the assumptions and analyses developed in the planning process are updated and performed again for procurement with little to no reference to the prior planning work. This design has become a typical component of a regulatory prudency standard that requires that decisions are made with the most recent information available. In addition, as would be expected and as is sanctioned by the regulators, utilities may seek and/or exploit cost-efficient procurement opportunities that were not specifically planned for or identified in their most recent IRP. For example, Avista purchased the Lancaster plant output as it became unexpectedly available after completing the 2007 IRP analysis but before actually filing the plan, and substituted this resource for the own-build natural gas facility proposed in the IRP. Similarly, Sierra Pacific signed a PPA with Newmont as a strategy to retain this customer and, in the process, diverged from the planned resource mix. In these examples, the utilities adapted their procurement plans in response to changes in conditions unanticipated in the IRP.

In retrospect, the procurement decisions for the utilities discussed above seem reasonable and prudent. Therefore, resource planning rules that are flexible enough to allow the incorporation of new information as it becomes available are a way to secure least cost acquisitions and mitigate risk. This is the case in the case studies that we analyze, in particular of Washington and Idaho, which require frequent subsequent updates to the "original" IRP filings by the utilities under their jurisdiction. Even in Nevada, with a high connection between planning and procurement, the frequency of filings for IRP amendments was high with an average of four to five per year. This suggests that the value of new information for procurement is higher than the value of information developed during the planning phase.

Plans are not only updated very frequently, but also their content varies significantly even between subsequent processes. We find that plans—for all of the cases considered in this study—were drastically modified within a 2-3 year period in response to changes in the variables that we described above, especially load, regulatory environment, and market conditions[28]. The benefits of very flexible resource planning rules need to be assessed against the usefulness of such rapidly changing plans. The ongoing, periodic short-term fluctuation and adjustment in the procurement process further separates it from a long term forward looking planning process.

The relationship between integrated resource planning and rate-making is also worth noting. In both Washington and Oregon, IRP information informs the rate-making process; this information is taken into account in rate cases, generally in the sense of establishing consistency between a generic resource need identified in previous IRPs with a specific asset that the utilities wish to add to their rate bases. At the same time, the rules in both jurisdictions are clear in stating that the identification of a resource need in an IRP is by itself not sufficient to justify rate-basing of a specific asset. The Nevada approach brings the IRP process closer to rate-making, but the regulator does maintain discretionary authority over the ultimate selection of resources that go into rate base.

6 Conclusion

Planning and procurement are two fundamental activities conducted by utilities to fulfill their public service mission of providing reliable and affordable electricity. It is generally recognized that integrated resource planning is a stakeholder-driven process that provides guidance for future procurement decisions that, in principle, assure least cost and risk managed resource choices. To our knowledge, there has been no previous research that assesses the effectiveness or usefulness of resource plans by tracing their relationship to procurement decisions made after their filing. In this analysis, we compare the acquisition recommendations of IRPs conducted in the early-to-mid 2000s to the actual procurement decisions that followed. We assess differences in timing and type of resource acquisition, as well as whether the resource was owned by the utility or contracted. We complement this comparison with qualitative case studies of three jurisdictions, examining utilities', regulators', and other stakeholders' regulatory filings to understand the reasons reported by utilities to explain deviations between their originally-filed plans and their later applications to procure actual resources. In analyzing the case studies, we specifically look for information flows from the planning to procurement phases that provide support for these deviations and shed light on the empirical relationship between these two processes.

[28] The types of variables involved suggest that this situation is probably still prevalent, even if our analysis period includes the 2008/2009 recession.

We find that, in aggregate, planning and procurement levels were similar for the 12 LSEs considered in this analysis. However, the aggregate procured mix exhibited greater reliance on natural gas and less on coal than originally planned. In addition, three times more wind capacity was procured compared to what was planned. We find that the substitution from coal to natural gas CCCTs was possibly driven by an *anticipated* reduction in natural gas prices around 2007. Adoption of less-efficient SCCTs correlate to *actual* price reductions realized after 2008, but possibly also to their role in providing flexibility given higher wind adoption. In sum, natural gas prices do not appear to have an effect on the levels of procurement, only on the mix, when compared to resources that were originally identified in the integrated resource plans.

Examining planning and procurement by resource and by individual LSE, however, reveals a much wider variation that is not apparent from the aggregate analysis. We study the regulatory record to understand what explains these differences for three LSEs: Sierra Pacific, Idaho Power, and Avista. We find that differences are explained by uncertainty in several key parameters, the challenges in managing this uncertainty, and the variation in risk management methods employed in the planning and in procurement phases, respectively. Differences in levels of procurement were largely related to load growth, particularly from industrial customers but also influenced by economic performance. Differences in resource mix largely arise from regulatory decisions related to RPS and DSM targets, but also from relative fuel price differentials as found in the quantitative analysis.

We find that information produced in the planning phase is generally used in a fairly delimited way in the procurement phase, and that the connections between IRPs and specific procurement activities are for the most part rather informal both quantitatively and in terms of process. In some cases, utilities may seek and/or exploit cost-efficient procurement opportunities that were not specifically planned for or identified in their most recent IRP. In their procurement decisions, utilities generally aim to consider the most recent information available and this new information may have higher value than information produced previously in the planning phase. This in part reflects changes in conditions that may be quite rapid, which puts a premium on updating of information within the IRP cycle – that is, between IRPs. Indeed, we found that plans - for all of the cases considered in this study – were drastically modified within this 2-3 year period in response to changes in the variables that we described above, especially load, regulatory environment, and market conditions.

In Idaho, Washington, and Oregon, rules governing IRP at the time of the specific plans we studied were explicit in stating that integrated resource plans were not expected to dictate or fully determine subsequent procurements. Regulators understand that the utilities must take account of ongoing changes in numerous factors affecting resource needs and the appropriate ways to meet them. Our case studies found that this flexibility was warranted, and that the utilities did respond to changing conditions in moving from planning from procurement. At the same time, specific procurement activities were expected to take account of IRP outputs, at least in either confirming consistency of a specific acquisition with the most recent IRP, or explaining any deviation. Beyond this, exactly what information should be used, and how, is not formalized. For example, from the integrated resource plans and procurement activities in the three jurisdictions we studied, there is a there is little to no evidence on whether and how the sensitivity and risk analyses assessment developed in IRPs are applied in subsequent procurement decisions.

More carefully defining the appropriate links between integrated resource planning and procurement is an important problem as energy technologies, markets, and policy and regulatory goals evolve and become more complex. This has been recognized by the Washington Utilities and Transportation Commission, which has initiated a proceeding to study aspects of this issue. As the Commission notes:

> "Rapid technological advancements in the electric utility industry have altered the resource landscape and complicated the IRP modeling process. Resources that were still unconventional when the Commission adopted its rule [governing IRP] in 2006, such as wind and solar, have become commonplace on today's grid. Meanwhile, other technologies and options like energy storage… have offered new means of integrating renewable resources and managing the… grid. These resources, however, bring modeling challenges that strain traditional IRP models." (WA UTC, 2016, p. 2)

The challenges involved are exemplified by two of the Commission's questions: whether sub-hourly modeling can be introduced into the IRP process, and how the transparency of IRP models can be increased. Both are important, but there is a tension, if not inconsistency, between them. As with any additional detail to the types of computational models that are used in IRP, the increase in model complexity that would be entailed in introducing sub-hourly modeling would be likely to *reduce* transparency.

This problem is noted by Kahrl et al. (2016) in their study of the future of IRP. Among their recommendations is increasing detail in IRP modeling to represent renewable generation. They also highlight the need to "balance precision and transparency in [the] planning models" used in IRP, which they note will require "…determining where greater model complexity is meaningful." and (2) the continued use of simpler screening tools in parallel with more complicated models." Striking the balance in question is indeed a key priority for integrated resource planning, both in modeling and in the process, and Kahrl et al. are correct that this will entail attention to the benefits of added complexity. However, determining in a rigorous, quantitative manner exactly how this balance should be struck and how the value of complexity should be analyzed is an extremely difficult problem, and is essentially unsolved in energy planning modeling.[29] [30]

Kahrl et al. also recommend improved and increased use of risk analysis in IRP, including the use of risk-adjusted metrics in selecting preferred resource portfolios. From the perspective of our case studies, all

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29 Sanstad, (2015) discusses these issues at length.

30 Kahrl et al. also indicate the need for "…continued use of simpler screening tools in parallel with more complicated models." However, they do not identify what screening tools these are. They mention several utilities' use of stochastic analysis as "pre-screening step," but what this apparently refers to is a protocol for the joint use of capacity expansion and production cost models, both of which are quite complex.

else being equal both this and the use of more complex models would tend to further separate IRP from procurement and acquisition. The more complexity and detail in IRP and the selection of preferred portfolios, the more difficult it is likely to be to update and apply IRP information in "real time" to the continuing, ongoing procurement process. Efforts to make IRP more complex may not be warranted without formalizing and structuring the flows of information between planning and procurement and their value. While our analysis sheds light on the current status of these flows, determining the value of information and proper regulatory structures is an open area of applied research.

While this study has focused on examining and understanding the practical connection between planning and procurement, our analysis has also revealed several promising research directions. Acquisition of natural gas units by LSEs seems to be explained by a mix of the relative efficiency of turbines, their use as baseload or peaking units, and natural gas prices. Research into organized wholesale markets in certain regions of the U.S. suggests that these same factors may explain investment decisions in competitive generation supply (Borenstein and Bushnell, 2015; Hill, 2016). This finding highlights the need to conduct research into, for example, intra-day market transactions, which are actively used by some LSEs as hedging mechanisms for the short-term. However, these non-firm transactions are neither part of the planning process nor subject to the same scrutiny as firm procurement decisions. The impact of these transactions in a comprehensive procurement strategy, their connection to planning, and the costs and benefits for different stakeholders are an important area worthy of additional research. We believe this paper and these additional research venues will provide much needed empirical evidence for the assessment and improvement of procurement practices in the electric utility industry.

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