LBNL- 1006395

ERNEST ORLANDO LAWRENCE
BERKELEY NATIONAL LABORATORY

Load Forecasting in Electric Utility Integrated Resource Planning

Juan Pablo Carvallo, Peter H. Larsen, Alan H. Sanstad, Charles A. Goldman.

Energy Analysis and Environmental Impacts Division

October 2016

This work was supported by the National Electricity Delivery Division of the U.S. Department of Energy's Office of Electricity (OE) Delivery and Energy Reliability under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

LBNL-1006395

Load Forecasting in Electric Utility Integrated Resource Planning

FINAL VERSION

Prepared for the
U.S. Department of Energy
National Electricity Delivery Division
Office of Electricity (OE) Delivery and Energy Reliability

Principal Authors

Juan Pablo Carvallo, Peter Larsen, Alan H. Sanstad, Charles A. Goldman

Ernest Orlando Lawrence Berkeley National Laboratory
1 Cyclotron Road, MS 90R4000
Berkeley CA 94720-8136

October 2016

The work described in this report was funded by the National Electricity Delivery Division of the U.S. Department of Energy's Office of Electricity (OE) Delivery and Energy Reliability under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

Executive Summary

Integrated resource planning (IRP) is a process used by many vertically-integrated U.S. electric utilities to determine least-cost and risk-managed portfolios of supply and demand-side resources that meet future electricity needs of customers, comply with regulatory requirements and government policy objectives and, in many cases, fulfill obligations to shareholders. Integrated Resource Planning evolved in the late 1980s and 1990s from least-cost planning (LCP), which was developed to ensure that demand-side measures to reduce electricity consumption—especially end-use energy efficiency—were considered by utilities in addition to supply-side (generation) resources. Forecasts of energy and peak demand are a critical component of the IRP process. There have been few, if any, quantitative studies of IRP load forecast performance and its relationship to resource planning and actual procurement decisions.

In this study, we conduct a retrospective analysis of energy and peak demand forecasts for a set of integrated resource plans published by electric utilities operating in the Western United States. We analyze energy and peak demand forecasts from utility IRP plans filed in the early- and mid-2000s and compare these forecasts to subsequent actual observed loads. We also examine load forecasting techniques and sensitivity analyses; performance over time; the relationships among load forecasting, resource planning, and procurement; and strategies that utilities used to manage uncertainties in future load forecasts.

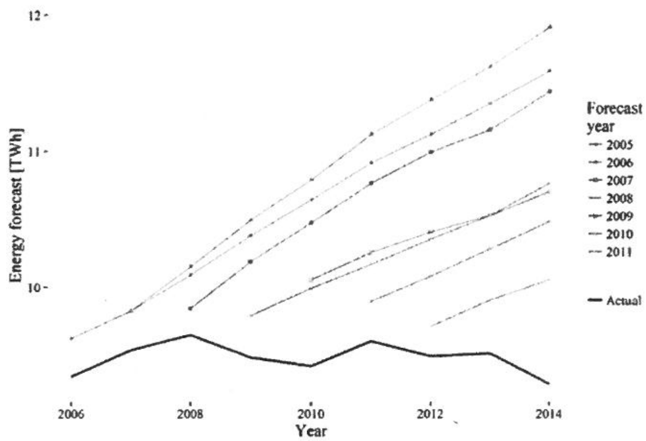

Figure ES-1 Load forecasts from seven subsequent IRPs and actual load for a Western U.S. utility.

Abstract

Integrated resource planning (IRP) is a process used by many vertically-integrated U.S. electric utilities to determine least-cost/risk supply and demand-side resources that meet government policy objectives and future obligations to customers and, in many cases, shareholders. Forecasts of energy and peak demand are a critical component of the IRP process. There have been few, if any, quantitative studies of IRP long-run (planning horizons of two decades) load forecast performance and its relationship to resource planning and actual procurement decisions. In this paper, we evaluate load forecasting methods, assumptions, and outcomes for 12 Western U.S. utilities by examining and comparing plans filed in the early 2000s against recent plans, up to year 2014. We find a convergence in the methods and data sources used. We also find that forecasts in more recent IRPs generally took account of new information, but that there continued to be a systematic over-estimation of load growth rates during the period studied. We compare planned and procured resource expansion against customer load and year-to-year load growth rates, but do not find a direct relationship. Load sensitivities performed in resource plans do not appear to be related to later procurement strategies even in the presence of large forecast errors. These findings suggest that resource procurement decisions may be driven by other factors than customer load growth. Our results have important implications for the integrated resource planning process, namely that load forecast accuracy may not be as important for resource procurement as is generally believed, that load forecast sensitivities could be used to improve the procurement process, and that greater emphasis should be placed on strategies to manage uncertainties in load forecasts.

Keywords: resource planning, forecast error, load, retrospective analysis, resource expansion, electric utility.

A comparison of load forecasts to actual energy use and peak demand reveals that energy consumption growth was overestimated by all but one utility over planning periods beginning in the mid-2000s and ending in 2014. Moreover, peak demand growth was also overestimated in eight of the eleven cases we examined (those utilities that reported their peak forecasts). Utilities that projected the highest growth rates in energy and peak demand also experienced the lowest actual growth, especially for observed energy consumption.

Furthermore, examination of forecasts from more recent IRPs indicates a persistent overestimation of demand growth over planning periods up to year 2014, even in the presence of much slower-than-anticipated actual growth (see Figure ES-1 for an example from one utility). A number of the utilities highlighted the effects of the national recession that began in 2008-2009 to explain this phenomenon. Over time, the utilities did adjust their forecasts of projected load growth downward in response to lower-than-expected demand, but continued to overestimate future loads. Most of the utilities indicated that they expected national and regional economies would follow a historical pattern of relatively quick recovery from the recession, which influenced their load forecasts in more recent plans. Accordingly, the slower-than-expected economic recovery contributed to over-estimates of future load in more recent IRPs.

We find some correlation between forecasting methods—and their relative complexity—and forecast accuracy. In addition, utilities that had the most accurate peak demand forecasts were also among the most conservative in terms of their expected peak demand growth. Utilities with relatively more complex models had less forecast error than those that employed simpler models. There are structural reasons that may also explain the relative accuracy of load forecasts. For example, we find that utilities with a larger share of industrial load in their mix generally had larger forecast error. We believe that this may be caused by the highly elastic and "lumpy" nature of industrial customer load as well as the difficulty in predicting entry and exit of industrial customers from a utility service territory. These results suggest that, among the utilities we studied, there may be small marginal benefits to the planning process of greater model complexity.

Load forecast sensitivity analysis is an important component of risk assessment and management within IRP process. In the context of our study, sensitivity analyses are especially important because strategies derived from load forecast sensitivity analysis may allow the resource plans to adjust as new information comes in. Over time, we find that utilities have improved the breadth and sophistication of their load forecast sensitivity analyses. However, we find that both older and more recent IRPs generally lack an adaptive component that details how utilities would respond in practice were subsequent actual values of critical input variables—like load — to correspond to those studied in these sensitivity analyses rather than to those assumed in "base cases." We also find that load variation from the base case produces differences in projected revenue requirements for utilities that are much larger than the differences in revenue requirements from the resource portfolios that are designed and compared to select the "preferred" one.

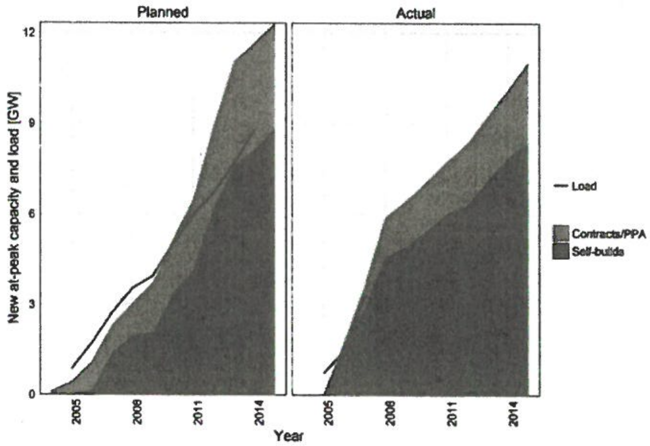

Figure ES-2 Planned and actual (procured) at-peak capacity with forecasted and observed peak demand.

For this sample of utilities, we find that aggregate planned and actual capacity expansion levels were generally consistent over the time period of our study. However, in aggregate, actual resource procurement decisions were not closely aligned with observed changes in load (see Figure ES-2). Actual incremental capacity additions were partially attributable to retirements of existing plants, which accounted for about 2.5 GW among our sample of utilities.

We find that load forecast methodologies have not changed significantly in the past 15 years, although there is evidence in more recent plans of the inclusion of potential structural change drivers such as distributed energy resources and electric vehicles. We did find that utilities which fundamentally changed their forecasting techniques had relatively larger forecast errors in earlier periods. This suggests an active effort to by the utilities to react to forecast error, although we do not have evidence that these changes led to reduced forecast error in subsequent periods. In general, we believe that our findings of load forecast performance and their relationship to procurement are applicable to current resource planning and procurement processes.

Our findings suggest that (1) load forecast accuracy may not be as important for resource procurement as previously believed, (2) load forecast sensitivities could be used to improve the procurement process, and (3) comprehensively addressing load uncertainty should be prioritized over developing more complex forecasting techniques. To the best of our knowledge, this is the first comparative and retrospective study of long-range energy and peak demand forecasts for electric utilities. We identify several key topics for further research to better understand the results and inform industry stakeholders about the role that load forecasts play in electricity sector infrastructure investments.

Table 12 **PacifiCorp**

Period	LSE-Projected AAGR	Actual AAGR
2006-2014	1.12%	1.47%
2007-2014	2.56%	1.01%
2009-2014	2.40%	0.47%
2011-2014	2.52%	1.63%

Tables 13 through 17 present analogous comparisons for the remaining LSEs in our sample, and show a similar over-estimation of load growth in IRPs over time. With the exception of Sierra Pacific, the forecast errors are increasing from older to newer forecasts.

Table 13 **PGE**

Period	LSE-Projected AAGR	Actual AAGR
2007-2014	1.78%	0.23%
2009-2014	2.10%	0.09%
2012-2014	2.30%	-0.18%

Table 14 **PNM**

Period	LSE-Projected AAGR	Actual AAGR
2007-2014	2.22%	-1.39%
2012-2014	1.72%	-4.62%

Table 15 **Puget Sound**

Period	LSE-Projected AAGR	Actual AAGR
2006-2014	1.75%	-0.19%
2012-2014	1.90%	-1.19%

Table 16 **Seattle**

Period	LSE-Projected AAGR	Actual AAGR
2006-2014	1.52%	-0.19%
2012-2014	1.93%	-0.84%

Table 17 **Sierra Pacific**

Period	LSE-Projected AAGR	Actual AAGR
2005-2014	1.40%	-0.53%
2008-2014	1.44%	0.33%

Overall, while the LSEs continually "course correct" (i.e., update and revise) their load forecasts, there appears to be a general pattern of persistent over-estimation of load growth.

Ongoing forecast adjustment is important and worthwhile, but our analysis reveals there is still systematic error patterns due to the methods employed in load forecasting. In the following section, we explore load growth sensitivities reported in older plans to understand the methods and strategies they developed and planned for to deal with this inevitable uncertainty.

7. Load forecast sensitivities in resource planning

We have shown that LSEs that developed IRPs in the early to mid-2000s observed economic conditions that generally contributed to optimistic load forecasts. While a few utilities have relatively smaller forecast errors—in both energy and peak demand—the majority of utilities evaluated in this study tended to over-estimate these values within their IRPs. The IRP process has evolved to consider the risks due to uncertainty of certain key variables, including future customer load. Accordingly, many LSEs use analytical techniques to measure how robust resource portfolios are to exogenous changes to these key variables. These analysis techniques are classified as scenario-based (i.e., sensitivity) and probabilistic (i.e., stochastic) risk assessments (see e.g. Wilkerson et al. (2014)).

In earlier sections, it was shown that actual load was generally lower than expected load. It follows that there is a risk of excessive capacity being built if expansion plans were not revised after the initial IRP was filed. This risk of acquiring more resources than needed – either by overbuilding capacity or through power purchase agreements – may translate to higher costs to consumers than necessary depending on whether these investments or contracts were actually made and included in the rate base. For this reason, we analyze the low and high load sensitivities from older IRPs to understand whether utilities were required to respond to potential deviations from their base case load forecast and how.

7.1 Review of load forecast sensitivity methods

In this section, we evaluate (i) the method used to create alternative load forecasts; (ii) the results of the load sensitivity analysis, (iii) the strategies developed by LSEs to respond to these alternative forecasts; and (iv) how LSE's methods have evolved from older to more recent plans. Detailed descriptions of load sensitivity methodology and results for each LSE are included in Appendix D and a summary in Table 18 below.

Evaluating the methods used to produce alternative load forecasts is an important step, because these methods reflect utility (and/or regulatory) motivation for considering a wider range of future conditions including alternative population growth, regional economic, and customer consumption scenarios. In the earlier plans, we find that most LSEs use percentiles or deviations from the base forecast as their alternative. In contrast, in more recent IRPs most LSEs are developing comprehensive future settings that reflect the interactions of several different fundamental variables such as economic and population growth and alternative technology adoption, among others. These scenarios usually analyze joint variation in quantitative variables such as natural gas and electricity market prices as an improved alternative to one-on-one variable sensitivity analysis. While the design of future scenarios remains a challenge, these new approaches should provide a better basis for robust planning processes.

We find three possible methodological approaches for sensitivity analysis of load forecast in older plans[15]. The first is LSEs that simply did not perform any sensitivity analysis, even when estimating alternative load forecasts. The second is LSEs that perform the analysis, but that do not produce an alternative portfolio. The last is LSEs that adjust their preferred portfolio to the new load conditions. The difference between the last two approaches is that the second holds investments as fixed and therefore test the impact of load deviation on operational costs/savings in their portfolios to verify that their preferred portfolio remained as the least-cost solution. In contrast, the third outcome produces an adapted portfolio that can be the basis of an adjustment strategy to alternative load conditions. We find that about half of the LSEs in our sample of older plans either were not required to perform sensitivities or were not required changing their preferred portfolios in light of new load conditions. In more recent IRPs, we find that most of the LSEs that perform sensitivity or stochastic risk assessments also develop new portfolios that are different than their original and preferred base case.

In most cases, reassessment of preferred resource portfolios in response to load forecast sensitivity analysis resulted in drastically different timing and size of resources. We inspect the sensitivity results in older and recent IRP to confirm that inter-scenario utility revenue requirement differences were usually much larger than inter-portfolio revenue requirement differences[16]. In some cases, the inter-portfolio valuation difference was small enough that it could be statistically insignificant. In contrast, several LSEs reported adjustments up to ±20%-40% of capacity under low or high load conditions. Load growth is generally the most important assumption in sensitivity analyses conducted by the utilities in terms of its quantitative effect. It follows that the development of methods to deal with variation in high-impact, uncertain variables—especially load growth—may be more relevant for utilities than the choice of a "preferred" portfolio under a given base case scenario.

[15] It is important to consider that LSEs develop their resource plans subject to the conditions, restrictions, and obligations imposed by the frameworks that regulate them. The reader should not interpret that the presence or absence of certain analyses or method is necessarily a choice of the LSE, but a requirement of the planning rules.
[16] In this context, inter-portfolio refers to the creation and evaluation of several different resource portfolios to find the least cost and lowest risk (i.e., "preferred") portfolio. Inter-scenario refers to the corresponding revenue requirement effects from varying assumptions of key variables including load growth, natural gas prices, capital costs, etc., usually performed as part of the sensitivity analysis.

Table 18 **Summary of load sensitivity methods in older IRPs.**

LSE	Source of alternative forecast	Assessment method	Horizon	Results	Strategy	Change from older to recent IRP
Avista	Economic model; Statistical (Distribution)	Scenarios; Stochastic	Long term for energy, short term for peak demand	Capacity adjustment; timing and resource mix not changed.	React to new information	Quantitative instead of qualitative scenario analysis; improved load model.
COPSC	Statistical (Percentile)	No information	Long term for energy, short term for peak demand	No information	No information	None
Idaho	Statistical (Percentile)	Scenarios	Short term for peak demand	Capacity and timing adjustment	Procure small, flexible resources	Stochastic instead of scenario analysis
LADWP	Statistical (Percentile)	No information	Short term for peak demand	No information	No information	None
NV Power	No information	No information	No information	No information	No information	No information
NW	Market prices elasticity	Scenarios	Short term for peak demand	Operational cost reassessment	No information	Stochastic instead of qualitative scenario analysis
Pacificorp	Statistical (Distribution)	Stochastic	Long term for energy, short term for peak demand	Operational cost reassessment	No information	Add scenario analysis.
PGE	Statistical (Percentile)	Scenarios; Stochastic	Long term for energy, short term for peak demand	Capacity and timing adjustment	Use market purchases/sales as buffer	None
PNM	Statistical (Percentile)	Scenarios	Short term for peak demand	No information	No information	Improved load model
PugetSound	Economic model	Scenarios	Long term for energy.	Capacity adjustment; timing and resource mix not changed.	No information	Only additional scenarios
Seattle	Economic model	Scenarios; Stochastic	Long term for energy	No information	No information	Improved load model
SierraPacific	Economic model	Scenarios	Long term for peak demand	Capacity and timing adjustment	No information	None

The adoption and intensive use of stochastic risk analysis in several recent IRPs is a good step in aligning inter-scenario and inter-portfolio decisions. However, there is still a general absence of methods to produce and follow-up with clear strategies that respond to higher or lower realized load. In one of the few examples of regulatory implementation of adjustment strategies, the Utah Commission requires Pacificorp to produce "resource acquisition paths." These paths transparently lay out responses to specific potential outcomes of relevant variables in the planning process and act as an "extension" of the typical action plan included in most IRPs.

In older or more recent IRPs, most LSEs did not report any type of analysis on the effects that alternative load growth scenarios would have on their planning outcomes. For those plans that did report these analyses, we identify two approaches to deal with this uncertainty: (1) resource flexibility and (2) market transactions. Flexibility refers to the procurement of smaller and quick deployment supply or demand-side technologies to adjust rapidly to new conditions (e.g. Idaho and Avista). LSEs report that they would expedite or defer deployment of these smaller and modular resources in response to higher and lower load conditions than expected, respectively Market transactions pertain to purchases/sales using non-firm transactions as a "buffer" for long-term, structural adjustment due to higher or lower than expected customer load (e.g. PGE)[17]. LSEs report that they would sell their output to the market if load conditions were lower than anticipated and purchase if load was higher.

Both of these strategies have limitations. The focus on flexible resources restricts the types of technologies that would be deployed and reduces opportunities for larger capital intensive projects. The use of market transactions, as suggested by some LSEs, assumes that market purchases are always on the margin, which is not necessarily accurate in all cases. Also, national or global economic performance will jointly affect electricity market conditions as well as load growth. Economic downturn may create surplus on electricity markets due to load contraction and therefore make market purchases more attractive. The use of market purchases or sales as buffers may not recognize this strategy. Finally, relying on market purchases as a strategy for long term adjustment implies coupling electricity price uncertainty with load growth uncertainty. This makes the entire strategy formulation much more complex.

[17] Other LSEs did mention in their IRPs market purchases as a hedging tool for short term supply-demand mismatches, but these market purchases are not discussed within the context of a load sensitivity analysis.

7.2 Quantitative analysis of load sensitivities

In this section, we study the base forecast, the range covered by the high and low load growth forecast estimates, and the actual load[18].

We observe that two LSEs, Northwestern and Sierra Pacific, developed very large "envelopes" around their base forecast that encompassed their actual retail energy sales and obligations (Figures 6 and 7). All other LSEs, including those LSEs with a relatively smaller forecast error, did not produce alternative forecasts that encompassed actual outcomes for energy sales. Most of the LSEs developed symmetrical and narrow forecast envelopes with a low average annual growth rate (AAGR) forecast boundary that was significantly higher than the observed average annual growth rate for energy (see Tables 19 and 20). The preceding is an example of the challenges of producing alternative forecasts that can span a wider range of possible future outcomes. It also reflects the tradeoff between the span of alternative forecasts and the complexity of the strategies to address them: a larger span requires a more sophisticated sensitivity analysis and strategy development.

Table 19 **Average annual growth rate for actual and forecast load, with sensitivities.**

	Energy AAGR			
LSE	**Low Forecast**	**Base Forecast**	**High Forecast**	**Observed**
Avista	0.3%	1.7%	2.9%	-0.1%
COPSC	1.6%	1.8%	2.0%	-0.4%
Idaho	1.5%	1.7%	2.3%	-0.1%
LADWP	-	0.6%	-	0.0%
NV Power	-	2.3%	-	0.1%
NW	-1.7%	0.6%	1.9%	1.2%
PGE	1.2%	2.6%	3.1%	0.2%
PNM	-	2.2%	-	-1.4%
PacifiCorp	1.1%	1.9%	2.1%	1.3%
Puget Sound	1.2%	1.7%	2.3%	-0.2%
Seattle	0.3%	1.1%	1.9%	0.2%
Sierra Pacific	-0.2%	1.4%	2.5%	-0.9%

We also evaluate the performance of alternative peak demand forecasts. The results for the peak demand forecasts are different than the results for the energy forecasts. Observed energy consumption growth was generally less than anticipated, but peak demand growth exhibits mixed

[18] In the case of Pacificorp, which does not provide point estimates for its alternative load growth forecast but a distribution of values, we use the 10th and 90th percentiles as the low and high values, respectively. No alternative energy forecast information was reported for LADWP, NVPower, and PNM, and no alternative peak demand forecast were available for NVPower, NW, PacifiCorp, and Seattle.

Then, retirements can account for about a third of the excess procured capacity compared to actual load[21].

The actual response of LSEs to lower-than-expected load conditions stands in contrast to their reported results and strategies from the load sensitivity exercises described in section 7. Many LSEs found important changes in resource acquisition timing and capacity when applying alternative load forecasts in their IRP modeling exercise. We do not see this reflected in practice as most procurement capacity and timing decisions are consistent with base case expansion even under actual low load outcomes. The fact that procurement is persistently aligned with load forecasts is in line with the findings in section 6, with LSEs systematically forecasting positive and higher growth rates than informed by very recent observed values. Our cursory review does not support that load sensitivities had an important role to inform procurement decisions because we do not see adjustment strategies reflected in quantities procured. Acquired resources seem to generally follow the original planning, regardless of the short and medium term performance of load forecasts and of actual energy sales and peak demand.

10. Summary and conclusion

We have quantitatively and qualitatively analyzed the methods for and performance of load forecasts for a set of electric integrated resource plans created by utilities in the Western U.S., and examined load sensitivities and the relationships among load forecasting, planning, and resource procurement. A comparison of forecasts to actual energy use and peak demand reveals that all but one of the LSEs overestimated energy consumption growth over planning periods beginning in the mid-2000s and ending in 2014, and that eight of the eleven LSEs that forecast peak demand also over-estimated this quantity. In addition, we find that most of the LSEs that had the highest expected growth rates also experienced the lowest actual – in some cases negative - demand growth.

Furthermore, examination of forecasts from more recent IRPs indicates a persistent overestimation of demand growth over planning periods up to year 2014, even in the presence of much slowed actual growth, for most of the LSEs in our sample. A number of the utilities highlighted the effects of the national recession that began in 2008-2009 to explain this phenomenon. Over time, the utilities did adjust their forecasts of projected load growth downward in response to lower-than-expected demand, but continued to overestimate. The IRP documentation suggests that for most of the LSEs, to a significant extent this apparently reflected an expectation that the national and regional economies would follow a historical pattern of relatively quick recovery from the recession. Thus, most utilities expected that load growth

[21] We recognize there are other concomitant factors that could influence resource procurement that we do not analyze here. For example, changes in renewable portfolio standards (RPS) targets may force larger adoption of renewable resources, or unanticipated earlier retirement of plants or termination of contracts may require larger capacity additions.

would recover as well. The actual, slower-than-expected economic recovery thus contributed to over-estimates of future load in more recent IRPs.

We find some correlation between forecast methods and complexity, and the accuracy of forecasts. In addition, the LSEs that had the most accurate peak demand forecasts were also among the most conservative in terms of their expected peak demand growth. LSEs with relatively more complex models had less forecast error than those that employed simpler models. Among the more complex techniques, Statistically-Adjusted End-use (SAE) models did not perform much better than other load forecasting methods and models. These results suggest that, among the LSEs we studied, there may be small marginal benefits to greater model complexity. There are structural reasons that may also explain the relative accuracy of load forecasts. For example, we find that utilities with a larger share of industrial load in their mix generally had larger forecast error. We believe that this may be caused by the highly elastic and lumpy nature of industrial customer load as well as the difficulty in predicting entry and exit of industrial customers from a LSE service area. This suggests that industrial loads should be modeled and risk assessed separately from the remaining loads to understand utility-level impacts of large adjustments.

Load sensitivity analysis is an important component of risk assessment and management in IRP. In the context of our study, it is especially important because strategies derived from load sensitivity analysis may adjust and impact resource plans as new information comes in. Over time, we find that LSEs have improved the breadth and sophistication of their sensitivity analysis of load forecasts. However, we find that both older and more recent IRPs generally lack an adaptive component that details how utilities would respond in practice were subsequent actual values of critical input variables—like load — to correspond to those studied in these sensitivity analyses rather than to those assumed in "base cases." More importantly, we find that load variation from the base case produces differences on revenue requirement for an LSE that are much larger than the differences in revenue requirement from the resource portfolios that are designed and compared to select the "preferred" one.

For our overall sample of utilities, we find that aggregate (pooled across utilities) planned and actual capacity expansion levels were generally consistent over the time period of our study. However, in aggregate, actual resource procurement were not closely aligned with observed changes in load. Actual capacity additions were partially attributable to retirements of existing plants, which accounted for about 2.5 GW for several utilities. It is possible that this apparent over-procurement reflects LSEs seeking to avoid resource adequacy problems by hedging against rapid rebounds in load that may exceed their ability to procure unforeseen required firm capacity. The volatility in observed peak demand growth rates and the quick recovery of some LSEs' peak demand provide evidence in favor of this.

We find that load forecast methodologies have not changed significantly in the past fifteen years, although there is evidence in recent plans of inclusion of potential structural change drivers such as distributed energy resources and electric vehicles. We did find that LSEs with more changes in their forecasting methodologies had previously had relatively greater forecast errors. This suggests an active effort to at least react to forecast error, although we do not have evidence that these changes lead to improvements in accuracy. In general, we believe that our findings of load forecast performance and relationship to procurement over our analysis period are applicable to current planning and procurement processes even if we studied decade-old plans.

To our knowledge, this is the first quantitative and comparative retrospective study of energy and peak demand forecasts by LSEs. This paper has been primarily descriptive and exploratory and as such our findings indicate several key topics for further research to better understand and to explain our results.

First, was over-optimism regarding resumption of economic growth following the severe recession of 2008-2009 the fundamental reason for the persistent over-estimation of load growth during the study period? If so, what does this imply about the role of economic growth assumptions in overall IRP processes and the strategies that may be derived from load sensitivity analyses? In addition, how much of this over-estimation may be due to under estimation of energy efficiency gains?

Second, what were the reasons for the divergence between load forecasts, on the one hand, and procurement, on the other? What were the differences in resource mix, timing, and market transactions between planning and procurement, and what the potential impact of these differences is?

Third, what is the balance between a better forecast to select the right portfolio and a better strategy to switch between portfolios and adjust to changing environments under a budget constrained planning process? What shape should these strategies take and what improvements would they have on the planning and procurement processes?

These questions, particularly the second, will be the topic of our second paper, in which we will investigate the connections between IRP and procurement processes in depth. We hope that both this paper and its sequel will contribute to the goal stated in the Introduction, of furthering the understanding of IRP among a diverse group of stakeholders, and contributing to the further evolution and improvement of planning methods and outcomes.

11. References

ABB-Ventyx, 2016. Ventyx Velocity Suite Energy Mapping Software. ABB-Ventyx, Boulder, CO.

Aspen, E3, 2008. Survey of Utility Resource Planning and Procurement Practices for Application to Long-Term Procurement Planning in California.

Avista, 2013. 2013 Electric Integrated Resource Plan. Avista Utilities Inc.

Avista, 2005. 2005 Electric Integrated Resource Plan. Avista Utilities Inc.

COPSC, 2011. 2011 Electric Resource Plan, CPUC Docket No. 11A. Xcel Energy.

COPSC, 2004. 2003 Least-Cost Resource Plan. Public Service Company of Colorado.

EIA, 2016. Electric power sales, revenue, and energy efficiency Form EIA-861 detailed data files [WWW Document]. US Energy Inf. Adm. URL https://www.eia.gov/electricity/data/eia861/ (accessed 3.18.16).

English, M.R., Schweitzer, M., Schexnayder, S., Altman, J.A., 1995. Energy efficiency advocacy groups Factors affecting their influence on DSM and IRP. Util. Policy 5, 55–63. doi:10.1016/0957-1787(95)00014-Q

Eto, J.H., 1990. An Overview of Analysis Tools for Integrated Resource Planning.

Foley, A.M., Ó Gallachóir, B.P., Hur, J., Baldick, R., McKeogh, E.J., 2010. A strategic review of electricity systems models. Energy, The 3rd International Conference on Sustainable Energy and Environmental Protection, SEEP 2009 35, 4522–4530. doi:10.1016/j.energy.2010.03.057

Goldman, C.A., Comnes, G.A., Busch, J.F., Wiel, S., 1993. Primer on Gas Integrated Resource Planning (No. 34144). Lawrence Berkeley National Laboratory, Berkeley, CA.

Hadley, S., Hirst, E., 1995. How integrated resource planning for US electric utilities affects shareholder interests. Util. Policy 5, 37–45. doi:10.1016/0957-1787(95)00012-O

Hirst, E., 1994. What constitutes a good integrated resource plan? Util. Policy 4, 141–153. doi:10.1016/0957-1787(94)90008-6

Hirst, E., 1990. Assessing Integrated Resource Plans Prepared by Electric Utilities [WWW Document].

Hirst, E., 1989. Integrated resource planning at electric utilities: The planning process. Eval. Program Plann. 12, 213–223. doi:10.1016/0149-7189(89)90032-3

Hirst, E., 1988. Regulatory Responsibility for Utility Integrated Resource Planning (No. ORNL/CON-249). Oak Ridge National Lab., TN (USA).

Hirst, E., Carney, J., 1978. Ornl Engineering-Economic Model of Residential Energy Use (No. ORNL/CON-24). Oak Ridge National Lab., TN (USA).

Hirst, E., Goldman, C.A., Hopkins, M.E., 1991a. Integrated resource planning - Electric and gas utilities in the USA. Util. Policy 1, 16. doi:10.1016/0957-1787(91)90045-7

Hirst, E., Lin, W., Cope, J., 1977. Residential energy use model sensitive to demographic, economic, and technological factors. Q. Rev. Econ. Bus.

Hirst, E., Schweitzer, M., Yourstone, E., Eto, J., 1991b. Technical competence of integrated resource plans prepared by electric utilities. Resour. Energy 13, 39–55.

Hyndman, R., 2006. Another Look at Forecast Accuracy Metrics for Intermittent Demand. Foresight Int. J. Appl. Forecast. 43–46.

Idaho, 2013. 2013 Integrated Resource Plan. Idaho Power.

Idaho, 2006. 2006 Integrated Resource Plan. Idaho Power.

Jamasb, T., Pollitt, M., 2000. Benchmarking and regulation: international electricity experience. Util. Policy 9, 107–130. doi:10.1016/S0957-1787(01)00010-8