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Long term load forecasting accuracy in electric utility integrated resource planning

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ABSTRACT

Forecasts of electricity consumption and peak demand over time horizons of one or two decades are a key element in electric utilities' meeting their core objective and obligation to ensure reliable and affordable electricity supplies for their customers while complying with a range of energy and environmental regulations and policies. These forecasts are an important input to integrated resource planning (IRP) processes involving utilities, regulators, and other stake-holders. Despite their importance, however, there has been little analysis of long term utility load forecasting accuracy. We conduct a retrospective analysis of long term load forecasts on twelve Western U. S. electric utilities in the mid-2000s to find that most overestimated both energy consumption and peak demand growth. A key reason for this was the use of assumptions that led to an overestimation of economic growth. We find that the complexity of forecast methods and the accuracy of these forecasts are mildly correlated. In addition, sensitivity and risk analysis of load growth and its implications for capacity expansion were not well integrated with subsequent implementation. We review changes in the utilities load forecasting methods over the subsequent decade, and discuss the policy implications of long term load forecast inaccuracy and its underlying causes.

1. Introduction

From the origins of the U. S. electricity industry in the 19th century with Thomas Edison's first power-generation plant in New York City, electric utility planning and operations have become highly complex, multi-faceted processes. Vertically integrated[1] U. S. utilities or load-serving entities (LSEs)[2] operating in states with a regulated electricity sector must determine how to provide electricity services to customers while complying with a range of energy and environmental regulations and policies, and respecting the economic objectives of both the utility and customers. These functions entail the use of a range of quantitative analytical methods, including computational modeling and statistical analysis. LSEs' core obligation is to ensure reliable, clean, and affordable electricity supplies for their customers. It follows that forecasts of electricity consumption (GWh) and peak demand (MW) over the time horizons of one or two decades are a cornerstone of LSE's planning process.

Long term load forecasts are a key input to integrated resource planning (IRP), which has become the core process whereby many U.S. LSEs, in consultation with regulators and other stakeholders, determine portfolios of electricity resources to meet demand over the long term. Such forecasts form the basis of utilities' capacity expansion planning, which consists of building or acquiring power generation plants, purchasing power from other sources, and other means of securing electricity supplies and services for their customers. Because energy and environmental policy goals are also a major element of IRP in many states, these forecasts also influence efforts to achieve larger social objectives. An important example is the consideration of energy efficiency and other demand side measures into utility planning, which has become a high policy and regulatory priority in much of the U.S.

Load forecast horizons employed in the electric industry often range from hours to decades. Hour and up to yearlong forecasts are categorized as short and medium term and are commonly used for operational efficiency. Decades long forecasts are categorized as long term and are the type used in utility planning. Short and medium term electric load forecasting has been and continues to be the focus of considerable research, and is the subject of a sizable literature. Hong and Shahidehpour (2015) provide a comprehensive overview. In contrast, there has been relatively little study of long term load forecasting. Willis and Northcote-Green (1984) compared methods and accuracy of

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[1] Vertical integration refers to the combination of different stages of production or segments in a value chain under a single company.

[2] "Load-serving entity" is a more precise term than "utility" to refer to firms that sell electric power to end-use customers. However, in this paper these terms will be used interchangeably.

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14 distribution system load forecasts. Nelson and Peck (1985) analyzed load forecasts from the 1970s prepared by the National Electricity Reliability Corporation (NERC), which combine individual utility service territory and regional level forecasts into a national level forecast. They found systematic over projection of demand. Mitchell et al. (1986) retrospectively evaluated the accuracy of long term energy and peak demand forecasts by utilities, government agencies, and academic researchers.

This paper aims to help fill the knowledge gap on long term forecasting by focusing on forecast performance or accuracy. It reports the results of a retrospective analysis of load forecasts produced in the mid-2000s by twelve utilities in the western United States. It also reviews the utilities' forecast methodologies and sensitivity analyses. This analysis is the companion paper to Carvallo et al. (2017), which studies the relationship between utilities' planning processes – including load forecasting – and their actual resource procurement decisions.

This paper is organized as follows. We report the sources of data used in the analysis in Section 2, followed by a discussion of the LSEs' forecasting methodologies in Section 3. In Section 4 we describe our quantitative analysis of forecast error. We then turn in Section 5 to a discussion of the effects of economic growth assumptions on forecast accuracy. We present an analysis of the LSEs' approaches to load sensitivity analysis in Section 6, followed by a discussion of changes to LSEs' load forecasting methods and inputs over time in Section 7. We conclude with Section 8, which holds a summary, discussion of policy implications, and suggestions for further research.

2. Data sources and methods

2.1. Information on forecasts

We collect forecasts from IRP produced from 2003 to 2007 by twelve LSEs across the Western Electricity Coordinating Council (WECC). We focus on WECC because this territory includes the largest U.S. LSEs that were required to file resource plans during this period (Wilkerson et al., 2014). Three large California investor-owned utilities (IOUs) were excluded because they did not use IRP during the analyzed timeframe. Aside from the California IOUs, the LSEs selected for this study are the twelve largest in WECC representing 34% and 32% of customers and retail sales in 2014, respectively.

The vintage years for the IRPs, which correspond to the base years for the forecasts, were selected for several reasons. These plans were created sufficiently long ago that their forecasts could be compared to actual[3] values over periods long enough to allow substantive analysis – to the year 2014, the most recent year for which these values were available at the time this study was conducted[4] (see Table 1). Depending on the LSE, between seven and eleven years of observed energy and peak demand are available to be compared to the original forecast. In addition, in reviewing plans older than those selected we found several shortcomings, including limited data and documentation of the type needed for this analysis. As discussed in Section 7, we also review one recent plan (produced between 2011 and 2015) for each LSE to understand whether and how the methodologies and techniques used to produce forecasts have changed over time.

The analysis period includes the 2008/2009 economic recession, which would be expected to have a substantial or even disproportionate effect on the accuracy of load forecasts made prior to its onset. It is a truism that all forecasts, including those of electricity use, are subject to error due to unforeseen circumstances. As we discuss later in the paper, the documentation indicates that the LSEs view economic and demographic variables as the primary drivers of demand, and the inevitable but always uncertain timing of events such as recessions means that such events are essentially guaranteed to affect long term load forecasts in not fully predictable ways, regardless of the forecast interval. Thus, an analysis period including the downturn that began in 2008, which was unusually severe, can if anything allow greater insight into the nature of load forecast accuracy and how forecast errors are addressed in the IRP process than might be available from studying a period without such an event. Put differently, the 2008/2009 recession provides an interesting "stress test" of LSE load forecasting procedures in the context of IRP.

We collect three basic types of numerical forecast information from each IRP: electricity use, peak demand, and the demand side resources of energy efficiency (EE) and demand response (DR).[5] For the forecast to actual comparison we used the base or reference case load forecast in each resource plan (all 12 LSEs produced these cases for energy and 11 for peak). We use high and low load forecasts where these were available for sensitivity analysis. LSEs account differently their energy efficiency and demand response measures, with some subtracting projected savings from these resources into their load forecasts, and some reporting them separately. For the forecasts that had not already done so, we subtract these savings from the raw energy and peak demand forecasts in order to calculate net load.[6] The use of net forecasts is appropriate for comparison with actual energy and peak demand, since the latter have embedded within them the effects of demand side programs and other acquired energy efficiency over the periods considered in the analysis.

2.2. Information on actual energy use and peak demand

Data on energy consumption and peak demand is obtained primarily from the Velocity Suite system supplied by ABB-Ventyx—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 load data as measured by retail sales, which is typically reported through the Energy Information Administration (EIA) Form 861 (EIA, 2016). In order to compare forecasts to actual values, it was necessary to identify the types of sales that utilities themselves considered as part of the *position*[7] for the resource planning process. All 12 IRPs in our sample accounted for retail sales to ultimate consumers when creating their forecasts, and most (10 LSEs) included transmission and distribution losses to reflect demand at the generation level. For the remaining two cases, we added transmission and distribution losses.

In addition, we review the IRP documentation to determine which LSEs accounted explicitly for selected wholesale sales for which they had firm contracts at the time of the forecasts, and use data from EIA Form 412 and FERC Form 1 to identify and include appropriate wholesale sales as necessary. Finally, we use historical load information when available in the most recent LSEs plans to check our estimates for actual values.

[3] We refer to these also as "realized" or "observed" through the paper.

[4] In the case of PNM and PGE we selected the oldest plans we were able to find that included the required data. PNM filed its first resource plan in 2005 but it did not include most of the quantitative data required for the analysis.

[5] By the time the IRP documents we analyze were issued, adoption of demand side resources such as distributed generation or storage was very limited and usually not considered. Therefore, we limit our analysis to EE and DR.

[6] By doing this, we implicitly include in our assessment the performance of energy efficiency and demand response forecasts. We recognize that the actual demand side resources may differ from these forecasts, but we lack the data to test this.

[7] The position is a term used to describe the annual expected difference between load and resources to meet it. When load is expected to be higher than the available resources, it is referred to as a negative position.