Load Forecasting for Modern Distribution Systems

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NOTE

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PRODUCT DESCRIPTION

Load forecasting is a fundamental activity for numerous organizations and activities within a utility, including planning, operations, and control. Transmission and Distribution (T&D) planning and design engineers use the load forecast to determine whether any changes and additions are needed to the electric system to satisfy the anticipated load. Other load forecast users include system operations, financial planning, and electricity market traders.

This Technical Update describes the impact of distribution grid modernization on distribution system load forecasting and covers methods to develop accurate short term and long term load forecasts in the presence of DERs, DR facilities, energy conservation measures, electric vehicles, and other elements of the modern grid.

Challenges and Objectives

Load forecasting has always been a very challenging task that relies heavily on factors that are not under the control of the electric utility, such as consumer behavior, changing weather patterns, and overall economic conditions. The further into the future load is forecasted the greater the uncertainty. Grid modernization has added many additional uncertainties to the load forecasting process. Growing energy supply contributions from customer-owned DERs may offset load growth, which may eliminate the need to add new distribution facilities to meet load growth. However, due to the variable nature of many new distributed generating resources (especially wind and solar power generators), there is no guarantee that these generating resources will be available when needed most during peak load conditions.

The rapid growth of small-scale distributed generation, such as rooftop solar, has created the potential for a considerable number of “zero net energy” homes, which presents a major challenge for short- and long-term load forecasting. Modern tools are needed for short-term and long-term load forecasting to evaluate and mitigate the impact of these resources on distribution system performance. Load forecasting and planning tools must be able to evaluate distribution performance over annual profiles with many factors affecting load levels and characteristics.

Results and Findings

Load forecasting involves the accurate prediction of both the magnitudes and geographical locations of electric load over the different periods of the distribution planning horizon. Spatial forecasting is needed in order to plan sites and routes for feeders, substations, and transmission capacity in proportion to local needs throughout the system. Utility load forecasting relies on a variety of inputs and mathematical techniques to handle uncertainty and estimate possible future loading scenarios with “horizons” that can range from a few minutes to several years into the future.

Methods to accommodate the forecasted load should include Integrated Resource Planning (IRP), which involves mixing T&D system resources (system capacity) with demand side resources such as load control and Conservation Voltage Reduction (CVR), energy efficiency, conservation, and DG. Rather than spend money on adding new feeders and substations, the utility would spend money to encourage energy conservation and the use of efficient appliances (reducing demand), as well as put into effect good load control programs and CVR to reduce peak demand. To do IRP planning, planners needed more detailed information on customer type and end uses, including what contributed to peak demand (what appliances contributed to it, and how much) and what their timing was.

Applications, Values, and Use

Load forecasting tools and guidelines described in this Technical Update are demonstrated with real world distribution systems to illustrate the new approaches. The true value of advanced automation functions and distributed resources cannot be realized until these technologies and systems are incorporated into the distribution system load forecasting process. The project will continue to develop the load forecasting tools and methods, so that distribution system plans and designs can be optimized based on available technologies and systems.

Following are key benefits that members will be able to achieve though this project

- Members will be able to better plan investments in their electric distribution system through improved load forecasting methods that account for impacts of DERs, demand response, smart distribution applications, and other elements of the modern grid.
- Members will be able to assess commercially available load forecasting software tools described in this report.
- Members will be able to assess the economics and benefits of different applications as a function of their implementation costs.

Keywords

Demand Response
Integrated Resource Planning
Load Forecasting
Net Zero Energy Buildings
Spatial Load Forecasting

ABSTRACT

Load forecasting is a fundamental activity for numerous organizations and activities within a utility, including planning, operations, and control. Transmission and Distribution (T&D) planning and design engineers use the load forecast to determine whether any changes and additions are needed to the electric system to satisfy the anticipated load. Other load forecast users include system operations, financial planning, and electricity market traders.

This Technical Update describes the impact of distribution grid modernization on distribution system load forecasting and covers methods to develop accurate short term and long term load forecasts in the presence of DERs, DR facilities, energy conservation measures, electric vehicles, and other elements of the modern grid.

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1 INTRODUCTION

A first step in the planning of any power delivery system is a load forecast—a projection of the amount and timing of the future power demands the system will be expected to satisfy, perhaps including other data thought to be necessary for comprehensive determination of the system's future needs.

Power transmission and distribution (T&D) systems are dispersed across the utility service territory: a distribution system is deemed satisfactory only if it distributes the required amount of power, delivering it in proportion to the demand in each of many tiny neighborhoods throughout and across that territory. Therefore, a load forecast for power distribution system planning must forecast the amount and timing of power demand in every small geographic area of the utility service territory, with those areas being sufficiently small and specific to provide system planners with sufficient detail as to the location and density of local neighborhood demands so that they can successfully match system capability to local need. Such a forecast is called a spatial load forecast. Computerized methods to produce such forecasts have been used in the US power industry for nearly five decades.[1] They first became the focus of industry-wide attention and organized multi-utility development efforts in the late 1970s.[2] Computer applications to analyze and forecast distribution load in a way that supports distribution planning needs are a fixture throughout the power industry today.[3]

Currently power distribution systems around the world are evolving in design and operation, as both distributed resources and smart technologies are added so as to bolster their capabilities and enable utilities to provide new services and levels of customer attention. Distributed resources provide an ability to either produce power at the distribution level, or change the customer's load in a way compatible with system operating needs at the moment. Smart technologies includes a variety of approaches that, in aggregate, provide a way to operate systems closer to margins and with more response to momentary and area-specific needs than ever before. These can coordinate the actions of distributed resources to create synergy between their capabilities and those of the distribution system itself, further extending the benefits both provide. The power quality, reliability of service, and peak capacity of smart distributed resource distribution systems can go far beyond those of traditional power distribution.

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[1] A. Lazzari, "Computer Speeds Accurate Load Forecast at APS," Electric Light and Power, Feb. 1965, pp. 31–40
[2] EPRI Project RP-570, done by contractor Westinghouse Advanced Systems Technology from 1977 through 1979, had participation by Arizona Public Service, Tampa Electric, Pacific Gas and Electric, and Cleveland Electric Illuminating Company. It tested and developed computer programs to apply several different approaches to distribution load forecasting, studied the relation of error to small area size and planning needs, and ultimately produced report EL-1198, *Research into Load Forecasting and Distribution Planning*
[3] *Spatial Electric Load Forecasting – 2nd Edition*, H. Lee Willis, Marcel Dekker, New York, 2002

The successful planning of a smart, distributed-resource power distribution system requires analysis, evaluation and engineering that includes considerably more factors, some with greater detail, than what was needed for the planning of traditional distribution systems. Planning databases and methods need to expand and evolve to meet these needs, and that includes the load forecast. This report discusses load forecasting for modern smart distribution systems.

Chapter 2 begins the reporting by summarizing the changes taking place in power distribution systems as distributed resources and smart equipment and systems are increasingly utilized. It looks at six major trends driving this change, and three technological factors and changes that affect how the systems are implemented.

Chapter 3 discusses load forecasting with emphasis on spatial load forecasting, looking at what it involves and why, how it is done and when and by what means, and where and who does the work of forecasting load in the T&D planning cycle. It also reviews the major categories of approach to distribution load forecasting and summarizes the advantages and disadvantages of each.

Chapter 4 discusses load forecast requirements for traditional, current, and integrated resource planning applications; three "levels" of planning consideration that require increasing amounts of forecast detail in order to support good planning. It then moves to the major theme of the report: load forecasting for smart distribution systems, which is represented as a fourth level slightly beyond any of the other three. The requirements to accomplish load forecasting that can successfully support good planning of these future power delivery systems is presented.

Chapter 5 then reviews distribution load forecasting methods and currently available computer programs for distribution load forecasting, reviewing available commercial software tools for conducting distribution load forecasting, this review comprises a broad set that includes specialized tools such as LoadSEER, which are designed for power distribution applications, as well as development environments such as MATLAB, which allow users to customize and develop models.

Chapter 6 presents a series of cases studies that illustrate some of the emergent challenges and solutions for spatial load forecasting in the context of smart distribution systems, highlighting important forecasting issues and providing a practical context for the previous discussions. The case studies have been designed to address key issues such as the proliferation of new technologies, for example, Plug-in Electric Vehicles (PEV) and Distributed Generation (DG), and the implementation of Demand Response (DR), among others.

Chapter 7 summarizes the main findings, conclusions, and recommendations of this report and an overall assessment of industry status with regard to load forecasting. This Chapter also contains recommendations for future work.

2
THE CONTINUED EVOLUTION OF DISTRIBUTION SYSTEMS

An Evolving Change in the Basic Structure of Local Power Delivery

Since the late 19th century, a steadily increasing portion of the world's population has had access to electric power—a clean, controllable, and economical source of energy. Its widespread use globally has led to material improvements in quality of life, industrial efficiency and economical productivity for billions of people. During almost all that time, electric power has been produced and delivered to electric energy consumers over electric power systems that varied little in their major structural and design themes. The power system serving a city or region was dominated by a few large central generating stations, each consisting of from one to perhaps half a dozen industrial-scale power production machines (generators) along with the ancillary equipment needed to operate and maintain them in good working order. Transmission lines carried the power in bulk quantities to points throughout the region, where it was passed to smaller-capacity lines (distribution) on which it was routed to neighborhoods and eventually to individual homes, businesses, and other energy users. Figure 2-1 shows a traditional power system of this type.

Engineering standards, which here will be taken to mean the institutionalized, documented "way of doing things," varied, sometimes significantly, from one continent or region of the world to others, and they certainly evolved over time in subtle but important ways. Regardless, the vast majority of utility and industrial power systems on earth were built and operated to that overall system concept. The major characteristic of this traditional type of system is that power is produced in bulk at relatively few places but consumed at many. Typically there are several orders of magnitude more points of consumption—perhaps as 10,000 times as many power generation points. Throughout the 20th globally, until today there are few places of economic or demographic importance on this planet that do not have utility-supplied electric power. Along with roads and bridges, telephone, and water and sewer, electricity became the very foundation upon which first-world countries built their progress, quality of life, and economic prosperity.

A power transmission and distribution system (T&D system) is that portion of the power system that moves power from where it is produced to where it is consumed: basically it is the entire power system sans generators. The T&D system interconnects all the disparate parts of the system and thus determines the character of the system to a great extent. The T&D system is the focus on this chapter.

In the last two decades of the 20th century, significant changes—advances if perhaps not true breakthroughs – began to occur in several of the technologies that make up electric power systems. It became possible to build power systems powered by many more, but individually smaller, generating sites, that could function without the use of large, high voltage regional grids. Figure 2-1 also shows a distributed (modern/future) power system where individual customers may have generation and the "power system" may only be a local micro-grid connecting a number of local consumers together for power and reliability sharing. Under this concept no longer there would be thousands of times fewer generating stations than energy consumers:

conceivably, the ratio could be one to one. Such distributed power system, in which power production is dispersed widely throughout energy consumers rather than concentrated at a few generating stations as in a traditional power system, had different reliability, maintainability, and operability characteristics, as well as different economies of scale, etc., which shaped their use differently than those traditional systems. Neither type of system, traditional or distributed, is necessarily better, they are merely different. What seems clear is that the power system of the future will be neither, but a mix, a hybrid, of both.

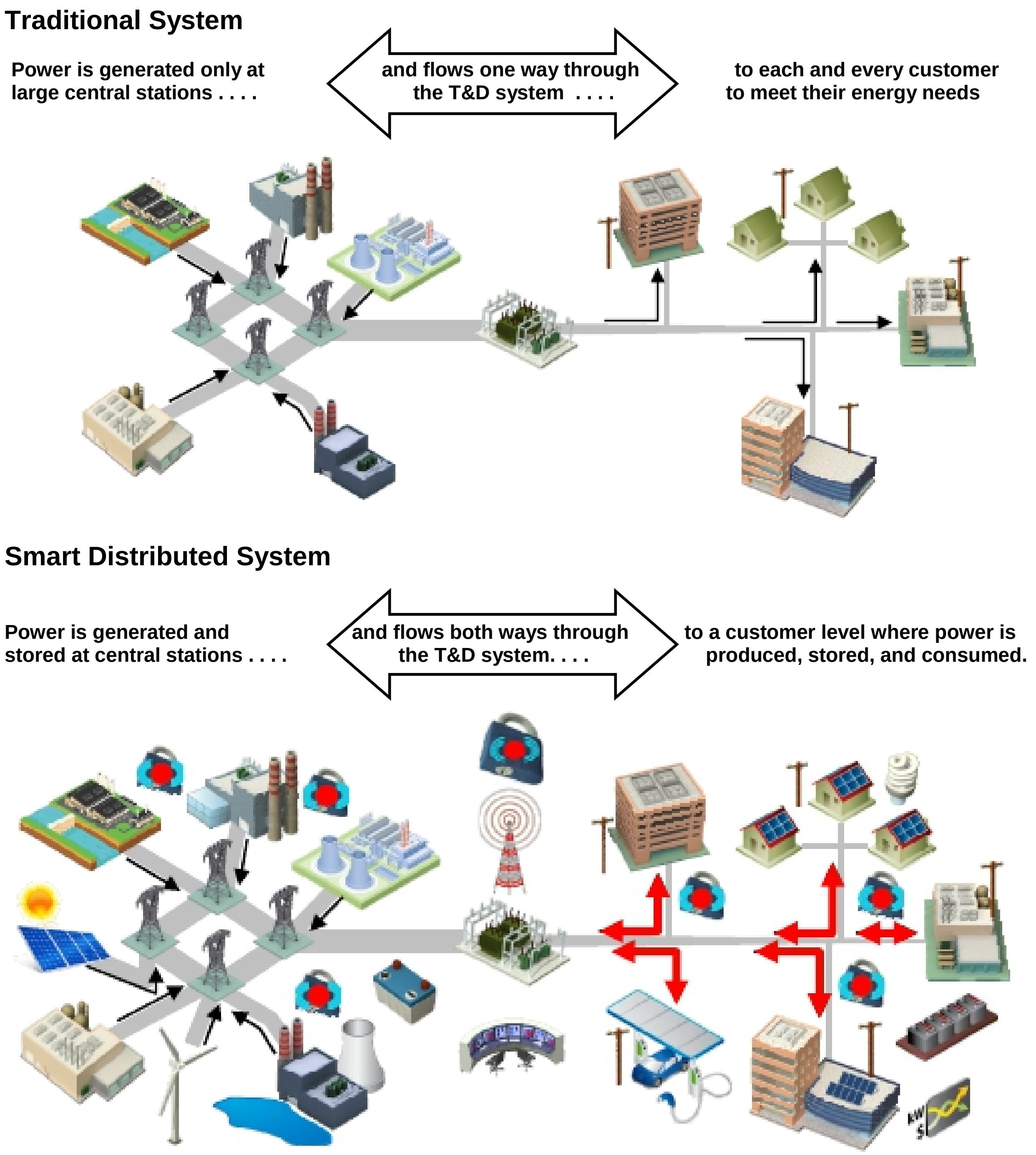

Figure 2-1
Traditional (top) and hybrid traditional/distributed (bottom) power systems[4]

This chapter reviews and summarizes the overall structure, function, design and performance of modern power distribution systems. It presents and discusses basic concepts behind system design and operation, when these basics play into the differences between traditional and modern

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[4] Estimating the Costs and Benefits of the Smart Grid – A Preliminary Estimate of the Investment Requirements and the Resultant Benefits of a Fully Functioning Smart Grid, EPRI Technical Report 1022519, March 2011

distributed power systems. These basics are among the factors that once required the traditional type of design solution but can now be accommodated by something different, and thus they are a key to understanding how the transition for one to the other, or the hybrid melding of the two, can be affected.

This chapter also discusses the forces and trends that will influence change in the need and uses for and the design and operation of power systems in the next two decades. The decisions that utilities, consumers and society make about electric power systems will be driven in large measure by how electricity is perceived as a critical utility, and by the value and benefits it can provide to an increasingly technological, connected, and "just in time" culture. New technologies, equipment and system improvements will provide a wide range of options from which to fashion the most effective solutions to societal needs.

Delivering Power Reliability: A Large Challenge for Any Utility

Regardless of type, power systems must be planned, engineered, designed, built, and operated. Their parts and sub-systems must be serviced regularly, maintained when broken and replaced when failed. Someone must pay for all of that, and that is usually done by charging consumers for the power they use in proportion to use or along the lines of well-established principles. The entirety of the system must be managed, which is the job of utilities, either public or private as the case may be. In this regard, distribution system planning plays a key role in the design of an economically and technically optimal system that allows supplying reliable service to existing and future customers. A key input for efficient distribution system planning is load forecasting.

The needs for electric service along with its potential role as part of the "infrastructure" that supports the North American economy and standard of living are all slowly evolving, as they have since the beginning of the electric era in the late 19^{th} century. The capital investment required to build, modify or change a power system is significant. Equipment is expensive because it is designed for long life and high levels of safety, and thus very robust. The labor required for construction and installation is considerable, and expensive (much if it requires special skills and training). Neither utilities, consumers, or society as a whole can afford to make wholesale replacements of existing systems just because they are obsolete in some ways compared to newer technologies, or because they are getting old and might require increasing attention and service. Practically speaking, utilities can only afford to make incremental investments and changes.

Factors Shaping the Nature and Use of T&D Systems in the Future

Increasing Need for Service Reliability

Viewed over the very long term— since the beginning of the electric era in the late 19^{th} century —the need for continuity of electric service and improved power quality (voltage regulation, etc.) has grown slowly but steadily. The service reliability of modern power systems is generally very good, with typical delivery performance exceeding 99.98%. Voltage regulation is generally within 3%. While this achievement is quite good, the widespread use of digital controls, robotic machinery, and smart systems for many critical infrastructures means that it is often not considered good enough: electric service interruptions, voltage sags, and high harmonic contents, even if infrequent and/or of short duration, can cause noticeable, sometimes significant, costs and consequences that electric energy consumers wish to avoid.

That said, it is not clear that any long-term societal or consumer need for even higher levels of electric service reliability and quality will be satisfied by a general improvement in the performance of utility power systems. The widespread use of uninterruptible power supply (UPS) systems shows that customer side options, particularly at the appliance- and installation-specific level, are a viable option in many cases. Many of the needs for reliable end-use performance of critical systems and equipment can be met by such means. At some point, the cost of improving the reliability of power systems, which serves all consumers and all demands, is not justified by the value that that increased reliability provides to those few consumers and demands that require extreme levels of service reliability. The power industry may be near that point—at least in some ways. In many cases the marginal cost of reliability and power quality improvement per kW is much lower for customer-installed UPS-like systems, than for improvements made in the electric grid. The only widespread exception is likely to be an increasing regulatory expectation for improved storm and energy response (better planning for major storms, quicker and more optimally managed damage repair and restoration), which will be discussed separately, below. Thus, with regard to future and evolving power systems, the important points with respect to reliability and power quality are:

- Demand for high levels of reliability of service and power quality will continue to increase, probably slowly, but steadily, at least in some industries and some areas of society.
- What often matters is the reliability at the consumer/appliance level. If a homeowner's lights and power do not go out, it is irrelevant to them if the distribution feeder circuit serving their neighborhood is out of service. Similarly, if the lights do go out, the effect is the same whether due to the utility circuit having a problem, or because of a failure in the consumer's UPS. It is the combination of service quality and reliability given by the utility *and* any special service equipment installed locally that is what matters to each consumer.
- Localized "utility system solutions" to reliability and power quality, such as whole-building or even neighborhood-scale UPS and power regulation systems, or high-reliability local virtual micro-grids, provide the ability for utilities and consumers to vary reliability where and as needed. High reliability service can be arranged only to those areas/consumers/loads that need it and are willing to pay the price. In fact it is not even necessary for the utility to be involved and many regulatory venues may decide that, beyond providing a satisfactory standard level of reliability, utilities are not required or even allowed to address the market for superior levels of reliability. However, it can be difficult to separate reliability from efficiency in some ways.[5] For this reason, many regulatory venues may permit or even encourage the utility to offer different types of service availability at different pricing structures.

A Different Type of Reliability: Increasing Inter-Infrastructure Dependence

Electric power is only one of several major "infrastructures" upon which the efficient and safe functioning of modern society depends: water, gas, transportation and communication, along with fire, police, and emergency services are others that are absolutely critical. Slowly, over time, these infrastructures have become more interdependent, the functioning of any one

[5] A load that is "controlled"—turned off for a period of time—in the interests of system or energy efficiency or due to a resource constraint has been denied service and thus is without power. Since RTP demand response systems work on a price-signal basis, one can view that all interruptions in service have an economic price and should be viewed through this one lens, in which case the utility offering very high levels of reliability for high prices is only consistent with its demand response program.

dependent on the proper function of the others. Transportation depends on electric power to operate street lights and traffic control systems, and to run pumps to keep underground tunnels dry. But utilities depend upon the road system to get to their systems during storms in order to make repairs—and so forth.

Electricity, in many ways, is at the heart of this intertwined necessary infrastructure. Without it water systems don't treat and pump water, sanitation systems don't take care of sewage, roads don't work well, land-line and cellular telephones don't work for long, and police, fire, and emergency services are seriously hampered. Further, society doesn't function even to a basic level of meeting absolute necessities. During post-hurricane periods in Florida through 2005's extreme hurricane season, and after *super storm* Sandy in the Northeast US in late 2012, a problem rising far above the level of severe inconvenience to become a public safety issue was the lack of essential retail and services caused by sustained power system outages. Without power, local stores that provide gasoline, ice, prescription drugs, emergency medical services, food and clean water, and other basic functions, could not function. Being without power at home was inconvenient and uncomfortable for millions of people. Most important, being in a community completely without power was much worst—intolerable—for hundreds of thousands.

Without a doubt, the experiences from these and other similar large, widespread storms will change societal perception of what, where, when, how, and why utilities must "harden" their distribution systems again storms, earthquakes, and other natural disasters. It will lead to revisions in expectations and requirements for restoration practices and resources. Exactly how this takes shape will be determined over time, but no doubt systems will be required to be more robust, and complexity of system design and operation will increase—perhaps greatly. Future systems may require "smart" equipment just to meet these needs. Very likely "multi-infrastructure" planning may become a required function in large metropolitan areas, with electric, roads, water, emergency services, and minimal levels of essential local retail services, all planned together to some extent. Such needs would in some ways alter the needs for electric load forecasting and analysis, as well as utility system planning.

Growth of Demand for Electric Power

Historically electric demand has grown steadily from the late 19th through to the early 21st century: in the total amount of power consumed, in the number and variety of devices that use electricity, and in the number of people and businesses that wish to use these devices. Historically, appliance and equipment technology improvements have led to greatly improved energy efficiency. Conservation, energy awareness, and the effect of demand elasticity as prices slowly rise, have limited the rise in electric consumption levels. But in spite of all this, overall electric consumption continue to rise modestly over time, partly due to the fact that technological progress seems to provide new electric demands. Modern television technology may provide for much more energy efficient circuitry and screens than those of three decades ago, but the 25-inch screens of the late 20th century are starting to be replaced in many homes with 80" three dimensional systems. Electric vehicles, where purchased by a homeowner, increase household usage by about 50%.

Aging Infrastructure

Aging equipment, systems, and control systems are a very real issue for utilities and society in general. Many existing power systems have large portions of equipment in them, equipment that is old. Usually, this older equipment is geographically concentrated, so that there are areas with the power system where nearly everything is worn out or at an age where it soon will be. This is particularly true in the central portions of many large American and European Cities.

Old equipment fails more often than new, so the utility does see an increase in service reliability problems. It has to be replaced when it fails, and that can be expensive. It requires more frequent inspection maintenance and service, often of an unplanned nature, and that raises operating costs even if it does not suffer outright failure. Older equipment and systems may not be as efficient or competitive as modern equipment, leading to a business disadvantage. It has to be replaced when it fails, and that means increasing cost and perhaps the opportunity to not make the replacement and use some other, newer approach.

Electric power equipment is designed for harsh service and long lifetimes. Most categories of power system equipment have expected service lifetimes longer than might be thought—perhaps 50 to 70 years (not allowing for storm damage of non-failure related causes of replacement). But another consequence of long-life design and the variations of service conditions is that the standard deviation of lifetime is also very long, too. Average equipment lifetime might be 70 years, but some equipment will fail at only 30 years, while other units will last past 100 years in service. The variation in lifetimes of a significant portion of a system's equipment may be on the order of or even longer than the average lifetime. Add to this the fact that the equipment in a utility system was installed over a long period of time—decades, and failures and equipment service problems created by wear and tear can appear, both perceptually and statistically, to be very random in nature: not predictable or easily manageable. Wholesale replacement of old equipment is not a particularly effective or affordable option. Replace old equipment just because it is old, and a lot of good equipment would be thrown out with the bad: for instance among even 60-year old wooden distribution poles, a large portion might have an expected 15 years of dependable service left in them, even if a small fraction are not serviceable.

The real problem is that "high" levels of aging equipment failure aren't that high. The failure rate of equipment in a power system in very good condition is far below 0.1%, or less than 1 in 1000 unit failures per year, even allowing for some of the equipment being quite old. A failure rate so high that it is "unacceptable" to all—unaffordable to the utility, unacceptable from a service standpoint for consumers and regulators—would be just 1% annually. Aging can lead to levels at and above these, theoretical studies show that due to the combination of equipment having been added gradually, variations in when equipment fails, and the fact that equipment has been replaced/repaired/life-extended when reaching certain points, most power systems will never see a failure or "natural" replacement rate more than about 2% per year, no matter how bad the "aging" situation gets.

Managing equipment aging and its effects is very challenging because only a small portion of the equipment will actually need to be replaced at any one time due to age and its effects. The challenge for the utility is to find that equipment in and among the mass of old, but good, equipment. That however, is an issue especially relevant to load forecasting and planning. Instead, the salient power with respect to aging infrastructures is that they will not normally create situations where large, wholesale changes need to be made to the power system. Aging is certain to be a major issue affecting both the attention of utility management and the budget and spending patterns of the utility, but it is unlikely to create opportunities for a paradigm shift in system structure such as a shift to an all new, distributed power system to replace an aged traditional one.

Consumer Control and Free Retail Markets

Historically, there has been a long-term trend toward de-regulation of some utility markets, most notably telephone, followed by electricity. In many nations, the wholesale power market is de-regulated. In a smaller number, but still a substantial portion, the retail market for power is deregulated, too. One promise of smart technology is that it will permit customized and user-specified choices as to the quality-quantity-timing-price combination that each energy consumer wants, enabling two types of approaches:

- "Open" retail power markets in which multiple vendors of power and services provide that power over a common electric T&D system
- "Closed" systems in which a single local delivery utility offers a variety of different rate schedules and services offering packages to consumers

At present there are no strong indications that any one approach would be strongly preferred by consumers, regulators, utilities, and political considerations alike. Thus, it is likely that different nations and regulatory venues (states within the US, etc.) will take different approaches and that a range of retail level structures and system/market designs will establish themselves. Regardless, all of these energy consumers will have more choice among a wider range of power service options, and more involvement with and control over their own energy supply than just controlling only by managing usage directly.

New Technologies

As new materials, inventions, systems, and communications capabilities become available, individuals and society alike will expect them to be utilized in the electric power industry. For example, in many industries such as personal communications and automobiles, smart systems have led to reduced costs and noticeably better performance, in addition to new features and capabilities not available before its widespread use. There is an expectation among the public and regulators that smart technologies, will provide benefits, which while perhaps not fully identified yet will be both substantially and fully recognizable when such systems are implemented.

The issue for many utilities is in developing a technology-use plan that can meet those expectations on the one hand, while not creating a significant technology-based business risk on the other. *Investment stranded by obsolescence* is increasingly a major factor behind business risk. Partly for this reason, many utilities are reluctant to move ahead with new technology without a plan that includes recourse. In some cases executives choose "technology diversity" by committing to several technologies used in various aspects or areas of their system. They do not want to bind their companies too tightly to the long-term use and cost of equipment or system technologies that might be eclipsed or to long-term business commitments that may become obsolete or not preferred as new technologies become available. A major factor shaping these decisions is that the traditional power industry period of equipment usage and financial depreciation is much longer than the technological half-life of modern systems.

An example is the great investment some utilities have made in providing service to “data centers” —digital communications control and internet server warehouses which often have substantial 24/7 demand above 40 or 50 MVA per site. Many utilities made sizeable investments (in most case recompensed by the customers as a contribution to construction or in a long-term contract for power) in new circuits and reliability/power-quality equipment to serve these data centers. Regardless of payment mechanism, the concept is that sooner or later, the utility will pay back that investment with proceeds from business with that data center over the next many years. However, it is at least possible that advances in optical computing and other digital equipment areas will lead to newer generations of servers with yet higher computing and switching speeds combined with power/cooling needs reduced by an order of magnitude. Peak demands could drop for many of these facilities by an order of magnitude, and while demand for data communication and “cloud” servers can be expected to perhaps double or even triple demand for such service by the next generation, the net result would still be a drop to 25% to 33% of current expected peak demand levels. Fortunately, most utilities are protected from financial loss if this were to happen by the nature of their contractual arrangement with the owners of such server sites. But this example shows the inefficiency, from a total societal standpoint, of such solutions, and the major issue: the technical half-life of the demand’s technology is shorter than the financial lifetime of the financial instruments used to pay for the power system built to provide power to it. As smart systems and new equipment based on technological advances proliferate, this issue will become more of a factor for the industry.

Technology Trends

In addition to the societal and market-drive trends discussed above, progress in three areas of technology has created a new type of power system capability that differs noticeably from the traditional central-station centric system depicted above. The three technological trends are: Distributed Energy Resources, Energy Storage, and smart systems. They are addressed in order below.

Technology Trend 1: Improving Cost-Effectiveness of Distributed Energy Resources

The low voltage (LV) and medium voltage (MV) levels of the traditional power system are, in a very real sense, their own distributed resources. The LV utility grid in particular is distributed over the service territory, reaching every single customer and sized locally in direct proportion to local customer energy needs. However, the term Distributed Energy Resources (DER) in modern power systems is used solely to refer to power systems in which the electric energy itself is produced by machinery, facilities or systems that are distributed throughout the service area rather than concentrated in a few large central station generating plants, as was depicted earlier in Figure 2-1. Distributed resources include small generators that might be:

- Low head of small hydro power generation
- Wind energy generation
- Micro-turbine powered generation
- High- and medium-speed diesel generation

- Photovoltaic (PV) power generation
- Small solar thermal and tower generation

These small generators can be distributed throughout the utility service area, although not necessarily in direct proportion to the customer demand. Evidence as well as economics indicates that they make the most sense when installed for reliability purposes, and/or where the marginal cost of power T&D service is higher than average[6]. For example, in a rural area a three-turbine wind generator facility of 1 MVA capability might be located in a tilled field two miles from the farmhouse and harvest processing/drying facilities that create the demand for most of that power. In an urban area, a 2 MVA PV plant located on office rooftops might produce power that at times is moved several miles to serve nearby residential demand. But invariably these distributed generating sources are, on average:

- Closer to the energy consumers than is central-station generation: this means power delivery costs are potentially lower, reliability of power transmission is higher and esthetic and environmental impacts of the power transmission lines are all lower than for power delivery in a traditional system (all three because the pathway for power delivery is, ultimately, shorter than in a traditional system)
- Less efficient in overall unit cost of power than larger central station generating plants, as was discussed earlier. The margin might be small or large depending on technology and characteristics specific to each situation

The usefulness and popularity of DG rests on the economic, service quality, social, and market advantages that being closer to the customer has as opposed to any disadvantages created by the lower potential efficiency of per-unit power production.

DER can also include both Energy Storage (covered separately below) and non-generating resources that can be dispatched like generation. It can also include *demand response*, or load control, in which certain loads can be switched off for a time to keep system resources and demand in balance: from the standpoint of many system-operating decisions aimed at achieving and maintaining that balance, it makes little difference if generation is increased or demand reduced.

Dispatchable load control, whether direct (the appliances and equipment themselves are disconnected at times of "control") or indirect (voltage on a feeder is reduced slightly lowering the load of connected loads, or price is raised in a real-time pricing system) the result is the same: at the system operator's request, a change is made that affects the ratio of generation to demand. More than a few utility planners, managers, and regulators limit the term "demand response" to methods that put directly in control of the utility or system operator the customer appliances and equipment—methods such as direct load control or active demand limiters. In others cases, however, demand response includes programs and load-influencing methods that rely on customer or automatic (customer programmed) price-sensitive responses from the demand, such as real-time-pricing (RTP) methods, or in a few cases even programs that involve public appeals for emergency reductions. These less direct methods do not have the temporal immediacy of direct load control—the demand reduction may take seconds or minutes to affect.

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[6] H. L. Willis and W. G. Scott, *Distributed Power Generation,* Marcel Dekker, New York, 2000.

They also are not 100% certain; customers may override them in critical situations, etc., and so are less certain. However they are sometimes included as demand response and DER. It is best to inquire in each instance to avoid ambiguity and confusion.

Technology Trend 2: Effective and Economically Justifiable Energy Storage

Since the 19th century, it has always been technically possible to store electric energy; including storing it in what is effectively alternating current form. Alternating current energy could be “stored” overnight or for a longer period of time using for instance battery/inverter sets, compressed air storage, or pumped hydro power plants or flywheel systems. Into the late 20th century, available energy storage technologies improved in efficiency and performance/price but typically did not have a sufficient economic performance to make them effective on a small (distributed) scale. Pumped hydro has a very substantial economy of scale and this technology was relatively widely used at the transmission level in traditional power systems, almost exclusively in central generating station capacity ranges. By contrast, the technology for battery systems and other smaller energy storage devices like flywheels, etc. did not have a positive economy of scale. At any size, even into the early 1990s, these did not have a positive business case for widespread use.

Two changes affected these economic cases for energy storage. The first was not technological: the need for increased reliability of service made distributed energy storage more useful and valuable. A UPS is an energy storage system used for backup power during service interruptions. The use of very distributed systems for this purpose alone skyrocketed in the last quarter of the 20th century. The business case for this application of small distributed energy storage rests upon the following:

- The growing number of appliances and equipment that need absolute continuity of service, such as digital devices and robotic machinery. Overall, the value of reliability and continuity of service as opposed to energy itself is increasing.
- The duty cycle of UPS devices: the unit’s purpose is to stand-by with available power, not provide it on a routine basis. As such UPS batteries do not “fatigue” or wear out due to daily cycling, as do lead acid batteries for instance, after only a few hundred charge-discharge cycles.

In the last decade of the 20th century and into the 21st, improvements in chemical and energy storage control technologies, and improved energy storage itself whether by electrical (super- and ultra-capacitors), chemical (battery and mixture systems) or mechanical (flywheels, etc.) improved in nearly every important practical performance category. Energy density improved. Peak power capability improved. And service lifetime increased, too: the ability to repeatedly deep cycle the storage mechanism improved several fold. Late 20th century lead-acid batteries could perhaps do through 500 charge-discharge cycles before “wearing out”. Modern lithium ion batteries can go through five to seven times as many, which makes for a much better business case for non-UPS applications.

In addition, changes in energy density and in storage control technology were also important. Batteries and in some cases flywheels became light and compact enough to permit practical employment in useful electric vehicles for personal and light commercial use. Considerable research for the electric vehicle industry led to a reduction in the economy of scale of power-systems energy storage units and an ability to control storage quickly enough to make it instantly dispatchable and in many cases fast and accurate enough in control to become a system stability resource. From the standpoint of power systems, where weight and size are far less important criteria, the most important enhancement is the improvement in lifetime cycle counts. Research and development in the electric vehicle industry was important to utility applications, because it spurred development on these improved lower-cost storage means, and it led to a battery manufacturing industry that can produce low-cost energy storage systems for non-electric vehicle usage, too. Increasingly, positive business cases could be made for energy storage interconnected to MV, LV and even customer facilities.

Technology Trend 3: "Smart" Systems

No area of power system technology has improved more, or led to a more recognized change in the power system's future, than the advent of "Smart Grid" systems, which involve the widespread use of real time and near-real time measurement, communication between, and control among equipment and sub-systems. There are two general major areas of improved capability that combine to make smart power equipment "intelligent" and that lead to smart grids, whatever capabilities they have been designed to provide:

- Equipment-to-equipment communication. Largely due to improved bandwidth-cost-performance of digital communications, individual and small units of a power system can communicate in near-real time with both a central system if needed, and more importantly, with other nearby equipment. An end-of-feeder power monitor can inform the utility's Distribution Management System whenever it senses no power. It can also inform a nearby switch that there is no power at its site. A recloser on one circuit can know the status (open-closed) and loading of a recloser on a nearby circuit that forms the alternate route to the loads it protects. Such communication is not only possible, but becoming routine, made with commodity equipment.
- Sensors and monitoring equipment. Technological advance is widening the range of characteristics in a power system that can be measured and tracked, a good example being Phasor Measurement Units (PMUs). In addition, almost across the board, the cost of remote sensing of equipment status and power has been greatly improved as has the periodicity (frequency) of how often readings can be or are taken.

These two technology enhancements have led to substantial improvements in the control and performance of traditional power systems, using schemes in which remote monitoring is used to inform a central control (either automated or human) which will respond via remote control of generation and T&D equipment. This has and will continue to make a difference in the performance of traditional power systems.

But smart-grid advances have made an even larger impact on the control of DER and the nearby local distribution systems. The character of this change is subtle but fundamental. In traditional power systems, there were many units of equipment that were *automatic*. Reclosers and sectionalizers performed rather complicated actions – as they were built to do. Capacitor banks could be built so as to turn on or off depending on voltage, power factor, loading, or a combination. Voltage regulators and line-drop compensators varied voltage according to their "programming." All this equipment was automatic, varying their settings and performance based on what voltage, current, power factor, or other factors (temperature, time of day) it measured at its location.

But the two capabilities above, along with the use of cheap digital computation, now permits equipment to monitor conditions *nearby or elsewhere*, so that they respond not just the conditions at their location alone, but to those in other locales. Groups of equipment can be programmed to work together to behave in a similarly automatic manner, in a coordinated way, so that they support one another or unify their effects to have a larger overall impact of system behavior.

Distribution and customer-site equipment can be built so that it will "understand" the interactions and dependencies it has with neighboring equipment, and essentially re-program its automatic actions in response to local conditions and needs. For example, what were reclosers or sectionalizers in the past become "smart switches," aware of the network configuration, loading, and outages in nearby circuits and able to determine how to respond in various contingency and operation situations, should they develop. DER systems can vary response and priorities based on local conditions, automatically. The type of control and control topology does not matter[7].

Potentially, smart control of DER permits an isolated or local part of the power system that has some local generation in to be autonomous, at least for periods of time. This alone would not lead to any substantial change in the status quo of power system design, except where it is designed to be an independent micro-grid. If provided with enough local generation and energy storage, the local power distribution system in a neighborhood can fend for itself: it can provide for its own energy need, and operate on its own. The extreme case for this is the isolated micro-grid: a power system covering only a small area and a few customers, not connected to the larger regional power system. The independent local micro-grid might be a system the utility builds to most economically and efficiently serve a group of customers. But it also includes situations where a group of individually independent energy consumers (each has sufficient on-site generation, energy storage, and demand response control to meet 100% of their own needs) intertie their systems for purposes of mutual reliability and efficiency improvement.

But in addition, one can talk about a *virtual micro-grid*, an area of distribution within a larger power system that manages the local balance of generation, storage, demand, and circuit operation in its neighborhood, so that the power transfer across its boundaries is nil. This local power system may be tied to the larger, traditional power system, but in many cases does not normally exchange power with it due to its generation and storage resources and manner of local control.[8]

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[7] Whether this capability is executed through a central hub (the utility DMS takes all local readings and sends out control to each device), or whether each device figures it out for itself in an independent manner, or if a hierarchical control consisting of many local hubs operates the system, from a big picture result, the end product is the same.

[8] Exceptions would be during times of emergencies such as when local generation has an unexpected outage, when power would flow from the system into the neighborhood, or when local generation owners wish to sell power into the regional grid, in which case it would flow out and upstream onto the transmission system.

In other cases, a *hybrid distributed/distribution system* will be used, in which the local neighborhood grid fulfills its own needs during some times but relies on the central-station system, and vice versa, in a way intended to achieve overall power amount, availability and quality targets at lowest overall cost.

3
LOAD FORECASTING

This chapter discusses electric load forecasting in a distribution utility environment with emphasis on *spatial* load forecasting, including an overall review of its main features, data requirements, methodologies, challenges for implementation and trends.

Utility Load Forecasting

Load forecasting involves the accurate prediction of both the magnitudes and geographical locations of electric load over the different periods of the planning horizon.[9] Utility load forecasting relies on a variety of inputs and mathematical techniques to handle uncertainty and estimate possible future loading scenarios with "horizons" that can range from a few minutes to several years into the future. Inputs are a function of the timeframe and methodology utilized by load forecasting models (for example, time-series, econometric models) and can include:[10] a) historical load data, b) historical and predicted weather data, c) information about utility service territory (land use), d) time factors (hour, weekday/weekend, and season), e) customer class, f) special events and days, for example, holidays, g) economic indicators such as Gross Domestic Product (GDP), per capita income, h) electricity price, i) utilization of new technologies, and j) information about likely future developments, for example, opening of new factory or shopping mall, etc.

Load forecasting is a fundamental activity for numerous organizations and activities within a utility, including planning, operations, and control. The following is a summary of utility activities that rely on the availability of load forecasts:[11]

- Transmission and distribution (T&D) planning: as part of utilities' annual planning cycle planners utilize load forecasting tools to develop scenarios, define strategies, and prepare the utility system with enough anticipation to serve future loads in a reliable and secure fashion. Load forecasting horizons for T&D planning are typically 20 years. Evidently, load forecasting accuracy (magnitude, timing, and spatial distribution of load growth) is critical, not only to ensure equipment is operated within nominal ratings, but also to decide when and where is required to build new utility infrastructure, Here it is important to point out that lead times for building T&D infrastructure are in the order or years. Similarly, planners utilize load forecasting tools to evaluate the effect of planning alternatives, such as "do nothing" or "implement energy efficiency initiates", on the utility equipment loading, for example, substations, transmission lines, feeders, etc.

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[9] H.K. Alfares, M. Nazeeruddin, Electric load forecasting: literature survey and classification of methods, International Journal of Systems Science, 2002, Vol. 33, No. 1, pp. 23-34
[10] H. Seifi, M.S. Sepasian Electric Power System Planning: Issues, Algorithms and Solutions, Springer 2011
[11] T. Hong, Short Term Electric Load Forecasting, NCSU, 2010

- System operations: control center operators use hour and day-ahead load forecasts to ensure efficient and secure system operation, for instance, for generation dispatch, volt-VAr control, schedule outages and load transfers for equipment maintenance, implement demand response, etc. Load forecasting horizons for system operations can be hourly, daily or weekly, depending on the specific activity of interest.
- Financial planning: financial analysts utilize load forecasting to estimate future utility revenues. This information is in turn used by Senior Executives for strategic and tactical decision making, for instance, annual budgeting, ratemaking, etc.
- Electricity markets: traders utilize load forecasts for decision making in wholesale electricity markets, specifically in decisions involving energy purchase, risk management, congestion management, etc.

Given the variety of activities, data availability, data uncertainty, and different goals and requirements of each utility organization, different types of load forecasting models and techniques are utilized. Evidently, the further into the future load is forecasted the greater the uncertainty.

According to the time horizon, load forecasts can be broadly classified into three categories:[12] a) Short-Term Forecast (STF) which is usually over an interval ranging from an hour to a week, b) Medium-Term Forecast (MTF) which is usually from a week to a year, and c) Long-Term Forecast (LTF) which is longer than a year[13]. However, it is worth noting these time horizons can vary among utilities, for instance, some authors define MTF as ranging from 1 month to 5 years and sometimes 10 or more years, and LTF as covering from 5 to 20 or more years[13]. Figure 3-1 shows a summary of the typical data requirements for different load forecasting categories.

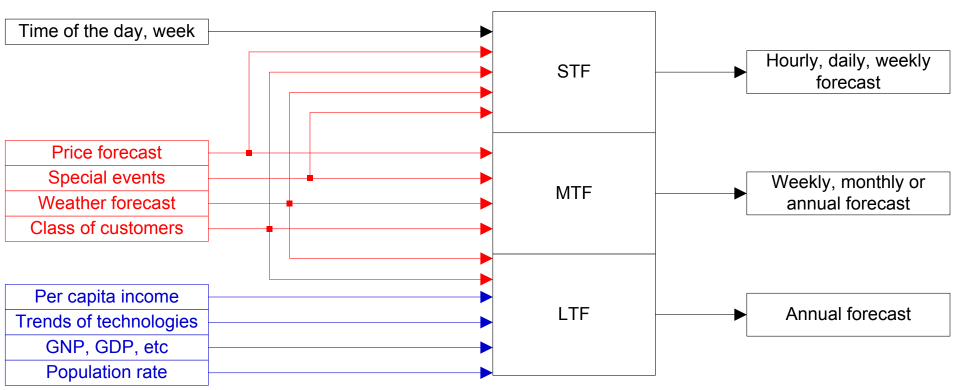

Figure 3-1
Typical data requirements for different load forecasting categories[10]

Evidently, the accuracy of the methodologies can vary significantly, and is also impacted by the quality of the data utilized in the simulations. Comprehensive reviews of STF, MTF and LTF have been published in the literature in the last decades,[14,15,16] and several articles have presented

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[12] A.A. Sallam, O.P. Malik, Electric Distribution Systems, IEEE Wiley, 2011
[13] J.H. Chow, F.F. Wu, J.A Momon, Applied Mathematics for Restructured Electric Power Systems: Optimization, Control, and Computational Intelligence, 1st Edition, Springer, 2004
[14] M.S. Sachdev R. Billinton C.A. Peterson, Representative Bibliography on Load Forecasting, IEEE Transactions on Power Apparatus and Systems, Vol. PAS-96, No. 2, March/April 1977. pp. 697-700

comparisons of load forecasting algorithms and summarized advantages and disadvantages. For instance, Willis and Northcote-Green[17] made a comparison of fourteen methods for distribution load forecasting, including trending, multiple regression, and land-use approaches. Similarly, Mogrham and Rahman[18] presented an evaluation five STF techniques, including multiple linear regression, stochastic time series, general exponential smoothing, state space, and expert systems (knowledge-based). Additional methodologies and comparisons are discussed by Alfares and Nazeeruddin.[9] It is worth noting that the selection of the forecast method must be based not only on accuracy but also on data availability, level of expertise of users, easiness of implementation, and information technology resources required for its implementation.

STF relies mostly on the utilization of historical load data, and historical and forecasted temperature data, as well as other weather variables such as Temperature Humidity Index (THI) and Wind Chill Index (WCI). Alternatively, it may also utilize economic indicators and land-use information, although the effect of the latter two is generally not significant since these inputs are expected to remain constant in the timeframe of interest. Numerous statistical and artificial intelligence techniques have been used for STF, including similar day approach, regression methods, exponential smoothing, time-series,[19] Artificial Neural Networks (ANN), expert systems, fuzzy logic, and support vector machines, among others. STF allows system operators to schedule spinning reserve and energy interchange with other utilities and it is also important for real-time control and security functions.[12]

MTF utilizes historical load and temperature data, and economic indicators. Land-use information is optional in this case, since it is likely to remain relatively constant in the timeframe of interest. MTF usually relies on a combination of end-use and/or econometric models, including statistical-based learning. End-use modeling analyzes patterns and energy usage characteristics of different customer classes (residential, commercial, industrial, etc) and the overall system. It utilizes descriptions of customer appliances, household sizes, equipment age, technology changes, customer behavior, and population dynamics. Econometric models utilize economic theory and statistic techniques along with economic factors such as per capita incomes, employment levels, and electricity prices[12].

LTF utilizes historical load and temperature data, economic parameters and land use information; the most popular methods are trend analysis, econometric modeling, end-use analysis and combined analysis. LTF is arguably the most important input for distribution systems planning. Hence, the rest of this document focuses on the requirements and challenges of conducting LTF for smart distribution systems. An important aspect that is necessary to emphasize is that STF and MTF generally aim at estimating load behavior or the magnitude of load growth at specific (discrete) T&D facilities, for example, substations, transmission lines and feeders. LTF on the other side, besides providing load growth results at existing facilities for

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[15] IEEE Load Forecasting Working Group, Load Forecasting Bibliography – Phase I, IEEE Transactions on Power Apparatus and Systems, Vol. PAS-99, No. 1 Jan./Feb. 1980, pp. 53-58

[16] IEEE Load Forecasting Working Group, Load Forecasting Bibliography – Phase II, IEEE Transactions on Power Apparatus and Systems, Vol. PAS-100, No. 7 July 198, pp. 3217-3220

[17] H.L. Willis, J.E.D. Northcote-Green, Comparison Tests of Fourteen Distribution Load Forecasting Methods, IEEE Transactions on Power Apparatus and Systems, Vol. PAS-103, No. 6, Jun. 1984

[18] I. Moghram, S. Rahman, Analysis and Evaluation of Five Short-Term Load Forecasting Techniques, IEEE Transactions on Power Systems, Vol. 4, No. 4, Oct. 1989

[19] For instance, Autoregressive Moving Average (ARMA), Autoregressive Moving Average with Exogenous Variables (ARMAX), Fuzzy Autoregressive Moving Average with Exogenous Variables (FARMAX), Autoregressive Integrated Moving Average (ARIMA), and Autoregressive Integrated Moving Average with Exogenous Variables (ARIMAX)

longer timeframes, it can also estimate expected load growth in areas where there are no T&D facilities at all. The latter is accomplished via spatial electric load forecasting[20] methodologies, which provide crucial results for T&D system planning and are discussed in more detail in the next section.

Spatial Electric Load Forecasting

Introduction

An electric utility's customers are spread throughout its service territory but seldom distributed evenly throughout that region. Figure 3-2 is an electric load map of a hypothetical city, very similar to many in the United States, showing the typical pattern of geographic load density in and around a large metropolitan area. In the core of the city, the downtown area has very high load densities, the result of densely packed, high-rise commercial office and residential development.

Outlying suburban areas have a lower load density. But the load density along major transportation corridors, even in the suburbs, is two to five times higher than that and there can be office parks and major activity centers with near-downtown levels of load density. Farther out from the urban core, in rural areas, load density is far lower still, because homes and businesses are spread far apart. In some agricultural areas, however, load density actually exceeds that of suburban areas, due to the intense loads of irrigation pumps, as well as of oil pumps in petroleum fields.

This spatial pattern of electric demand defines the power delivery need – the overall job of the utility's T&D system; regardless of where the power is generated or purchased, it must be delivered to customers in that pattern in order to satisfy energy consumers' needs.

Figure 3-2
Spatial pattern of electric load density

[20] H.L. Willis, Spatial Electric Load Forecasting, 2nd Edition, Marcel Dekker Inc., 2002

Spatial Load Forecasting

In order to plan an electric power delivery system, T&D planners need a map of electric load density like that shown in Figure 3-2, but for the future, so they can plan where to put how much capacity by the time when it will be needed. The map, or spatial forecast, must give that where, how much, and when information in sufficient detail, and with sufficient accuracy, to permit effective planning of T&D facilities. The "where" information is what makes spatial forecasting different from other types of forecast. Information on future load locations is needed in order to plan sites and routes for feeders, substations, and transmission capacity in proportion to local needs throughout the system – so planners can anticipate, plan for, and justify these new, key elements of their growing future T&D infrastructure.

Basically, planners need a prediction of the future electric demand map like that shown in Figure 3-2, with enough "where detail" to meet their planning needs, covering some key peak time(s) in the future: a spatial load forecast. The spatial forecast depicted in Figure 3-3 shows expected growth of the city in Figure 3-2 over the subsequent 20-year period. The growth shown in the later map represents the demand that the utility's T&D additions in this two-decade period need to address in an efficient and orderly manner. Effective planning of the T&D system requires that such information be taken into account, both to determine the least-cost plan to meet future needs and in order to assure that future demand can be met by the system as planned.

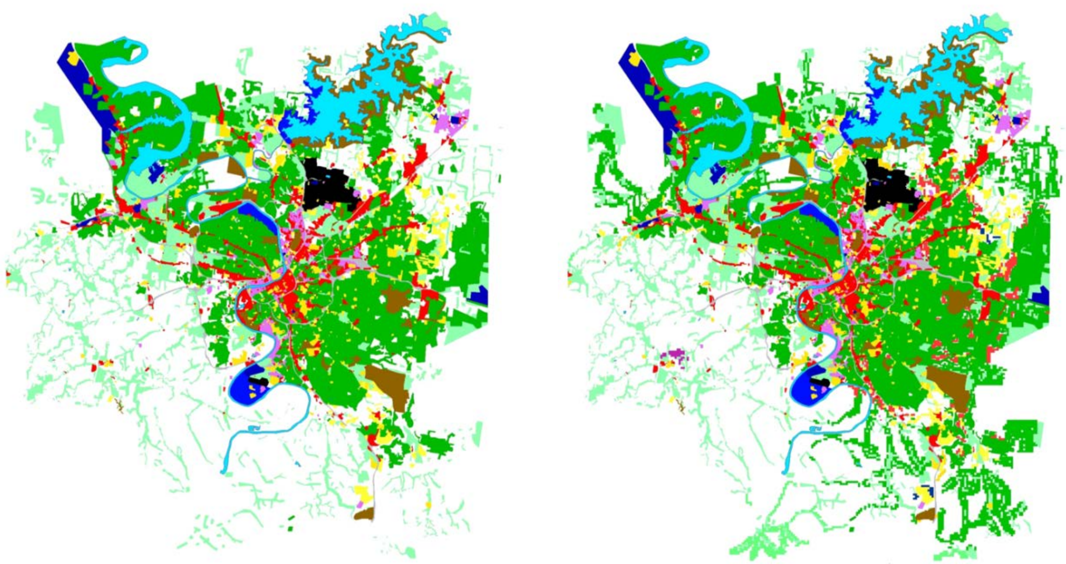

Figure 3-3
Spatial load forecasts produce "where" information for T&D planning.

Spatial Forecasting Methodology

Area Size and Type

The "where" element in a spatial forecast is addressed by using some form of small area forecast method: very simply, the utility service territory is divided into many, perhaps thousands, of small areas, and a forecast of demand is done for each. Figure 3-4 shows the two standard ways this spatial subdivision of area is done: by dividing the utility service area into areas based on equipment—areas defined by substation or feeder service areas—or by using a grid of uniformly shaped rectangular (usually square) areas. Table 3-1 lists the advantages and disadvantages of each approach as viewed overall by the industry.

As part of their T&D planning, many electric and gas utilities perform small area or spatial energy-use forecasts by equipment service area, for example forecasting future peak demands on a substation-by-substation or feeder-by-feeder basis. Equipment service areas (for example, substation areas) define the small areas. Using service areas of equipment like substations and feeders to define the small areas for a T&D forecast is convenient but creates two issues. It is convenient because the forecasts directly apply to planning purposes; a forecast by substation area immediately tells a planner if the projected load in the substation's current service area will exceed its rated capacity, and that is perhaps the key aspect of load-related planning. However, the equipment-area format creates two issues the utility must address carefully.

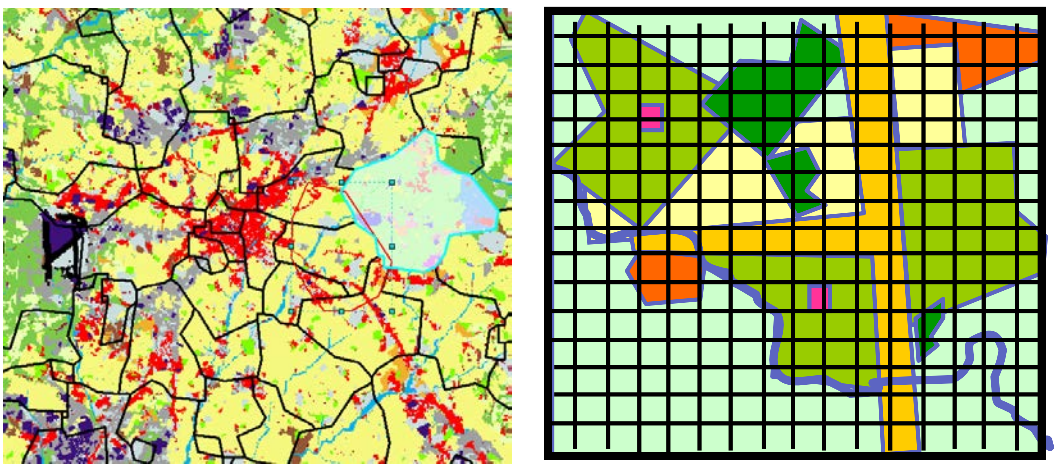

Figure 3-4
Small area formats for spatial load forecasting[21]

[21] Spatial load forecasts are accomplished by dividing the service territory into small areas, either rectangular or square elements of a uniform grid or irregularly shaped areas, perhaps associated with equipment service areas such as substations or feeders.

Table 3-1
Comparison of Small Area Formats Used For Spatial Forecasting

Type of Area	Typical Area	Advantages	Disadvantages
Equipment areas	Largest: Substation Service Areas Smallest: area served by portion of a feeder between two switches (about 4-6 per feeder)	1. Easy to relate directly to planning method (feeder-area forecast relate directly to feeder studies 2. Historical load data (feeder peak loads) easy to come by and simple to use in this format. 3. Compatible with simple and inexpensive algorithms such as trending, etc.	1. As typically done, provides insufficient spatial resolution to support all planning functions 2. Incompatible with almost all types of advanced land-use simulation forecast algorithms 3. Feeder or sub areas change size and shape over time (load is transferred back and forth)
Uniform squares	Largest: Squares 1 by 1 mile or 1 by 1 km Smallest: 10-acre squares (square areas 1/8 by 1/8 mile across	1. Usually provides more than enough spatial resolution and detail for all planning T&D needs 2. Uniform area size proves a big advantage with some types of forecast algorithms 3. Works particularly well with simulation-type methods and GIS-based software systems	1. Data gathering, preparation, and verification is generally more expensive than for equipment areas 2. Incompatible with simple and easy to use forecast algorithms: basically only simulation works well with it 3. Requires procedure and effort to relate small area forecasts on a square basis to feeders, subs, etc.

The first issue is that small areas defined by equipment areas change shape and size over time: substation and feeder areas boundaries change from time to time because of load transfers among them. Load transfers in the historical data distort analysis of historical trends adjust them in order to “remove” load transfers from historical data occupies as much as 80% of the time required to apply some equipment-based forecast methods (Figure 3-4). Even then is only partially successful, because often knowledge of all past transfers between substations and feeders is simply not available. There are some very innovative and clever methods to automatically reduce error caused by load transfers, but load transfers remain a concern with regard to error and cause near-excessive labor requirements in many equipment-based small area forecasts.

The second issue, just important, is spatial resolution, which has to be addressed carefully if an equipment-based small area forecast format is to be applied correctly and not “over extended”. The problem here is the amount of “where” information contained in a forecast—smaller small areas provide more detail as to where load is. How much information is needed, and how much is provided by a forecast, is an important consideration.

Generally, load projections done on an equipment area basis provide enough locational information to be useful for planning that equipment, but only at a high, “overview” level. For example, load forecasts done on a substation-by substation area basis do support the study of future substation capacity needs: they help identify when and by how much existing stations may be overloaded, and give important clues to determining if and when additional substations or substation capacity additions may be needed. However, a substation-by-substation forecast does not provide the entire “where” detail needed to support the study of effective solutions to overload and capacity problems.

Generally, to determine the best plans to mitigate sitting and capacity problems and to minimize cost and maximize use of substation capacity, planners need to determining if and how load transfers between substations (perhaps done with newly constructed feeder circuits and switches) can be an effective part of the plan. This requires more spatial “where” information than a substation-by-substation forecast will provide; it requires information on where load is within the substation areas. Is the growth expected on the western side of the substation area, where there are no existing circuits and capacity to transfer loads to? And so forth. Since factors like this are often a key element of sitting and planning new substations (the new substation area will be “cut” from existing substation areas via new circuits and load transfers), a higher spatial resolution—smaller area size—is needed.

Thus, a forecast done on a feeder-by-feeder basis will provide that required spatial detail for substation planning. But in a similar vein, it will not provide all the information needed to plan feeders in detail.

Experience and theory show that, overall, area size must be smaller—one fourth to one tenth the average service area size of equipment being planned—for the forecast to support wholly effective planning.[22] Partly for this reason many spatial forecast methods use a grid of small square areas of a size far smaller than substation or feeder service areas. Typical area sizes used in grid methods are 10 to 40 acres (squares 1/8th to 1/4th mile per side) although Duke Power runs its forecast algorithms at 1 acre resolution. Use of a grid assures sufficient spatial resolution, but is done mostly for two other reasons. First, there is considerably validity in a view that forecasting by equipment service area ties the forecast and existing equipment together so much that it blurs planning perspective—in a way putting the cart before the horse as far as objectively evaluating how to best serve future changes in load density is concerned. Second, a square grid is compatible with GIS and certain mapping systems, making use of data in those formats easier, and certain types of forecast algorithms, mainly land-use simulation methods, work best when the areas being analyzed are of constant size.

[22] H.L. Willis, Load Forecasting for Distribution Planning-Error and Impact on Design, IEEE Transactions on Power Apparatus and Systems, Vol. PAS-102, No. 3, pp. 675-686, Mar. 1983

But while having the forecast in a different geographic format than the equipment may be viewed as supporting objectivity in planning, it makes the forecast more difficult to relate to existing system capabilities (“How do I determine if this forecast indicates the load in the current substation area will in fact exceed its rated capacity?).

Regardless, many spatial forecast methods are in use around the world that work with either of the two small area formats shown in Figure 3-4 and described in Table 3-1. Very recently, GIS-based forecast methods that can simultaneously work with data input in either formats and “cut and chop” their spatial forecast into either or both approaches have been developed.[23] They work well, accepting data in mixed formats and producing forecasts that can be “output’ in either square grid or equipment-area bases. They require considerably more computing resources and set up effort, however, to get them going.

Spatial Forecast Methods and Algorithms

There are more than 60 different computerized small area electric load/T&D planning forecast methods that have been used and documented in the last 40 years. Spatial load forecasting continues to be a subject of interest for the industry[24,25,26,27]. By “method” we mean a basic analytical approach to performing the forecast: “let’s extrapolate load histories on a substation by substation basis using polynomial curve fit solved by multiple regression,” “Let’s model growth as moving from one area to another over time by fitting a spatial dispersion function to feeder load histories using a spatially symmetrical auto-regressive function of time.”). For any one method, there may be several different algorithms or computer code sets in use to apply it: For example, there are easily more than a dozen different ways that extrapolation of substation and feeder peak load histories are done, each a distinction different way of implementing the basic method.

Despite the wide variety of methods, algorithms, and programs and methods is use, all fall into three basic types of method, shown in Table 3-2: trending, simulation, or hybrid method. But before discussing the types of method, there is one key aspect to address:

All spatial forecasts are small area forecasts, but all small area forecasts are not spatial forecasts. A spatial forecast is a small area forecast in which every area was consistently forecast, one to the other, so they are part of a coordinated region-wide picture of future load growth, including how growth interacts from one area to another and “moves” spatially over time.

To understand this distinction, it is useful to consider the most obvious small area load forecast approach, one that many people immediately consider when first approaching the need to do a T&D forecast – trending of local area peak demands using some sort of curve fitting to past load

[23] “Dual-format” spatial forecast algorithms run only within GIS systems like ESRI’s Arc-Info and GE’s Smallworld, using optional features within the basic GIS to manipulate and exchange data among different SHAPE file formats.
[24] H.L. Willis, J.E.D. Northcote-Green, Spatial Electric Load Forecasting: A Tutorial Review, Proceedings of the IEEE Vol. 71, No. 2, Feb. 1983, pp 232-253
[25] H.C. Wu, C.N. Lu, A Data Mining Approach for Spatial Modeling in Small Area Load Forecast, IEEE Transactions on Power Systems, Vol. 17, No. 2, May 2002, pp. 516-521
[26] E.M. Carreno, R.M. Rocha, A. Padilha-Feltrin, A Data Mining Approach for Spatial Modeling in Small Area Load Forecast, IEEE Transactions on Power Systems, Vol. 26, No. 2, May 2011, pp. 532-540
[27] C.M. Brunoro, F.S. El Hage, C.C.B. de Oliveira, Integrated Model of Spatial and Global Load Forecast for Power Distribution Systems, 20th International Conference on Electricity Distribution (CIRED), Jun. 2009

history in each area. In this method, historical data on weather-adjusted peak demands for each small area (perhaps the peak loads for the past ten years) is extrapolated into the future using some sort of curve fitting method. This produces a forecast for every small area but not a spatial forecast. Each individual small area's forecast is based only on data about that small area, not its interaction with the region as a whole or its neighbors, and no consideration is given to the pattern of regional growth, or to the use of information that a statistical analysis of if and how growth varies among the set of all small areas of the whole. Basically, this is a set of N individual small area forecasts: no attempt has been made to analyze or forecast the set of small area load histories as a whole. The result is not a coordinated forecast of the region.

By contrast, a spatial forecast method applied to this same data would analyze the statistics of the load histories overall as a first step: how fast and how long they typically growth (on average and in the extreme), what the eventual maximum load was and how that related to growth rates, location, how growth rates and timing in one area are related to that of its neighbors, etc. Depending on its intricacy, it might look for patterns of growth among groups of small areas, etc. It would then apply all that analysis, in addition to curve fitting of the load history in each individual area, to produce a forecast for the region and every small area simultaneously. The result is a much better forecast by any standard: forecast error is reduced significantly and more importantly poor planning (forecast errors leading to poor decisions on location and capacity additions) is reduced by as much as a factor of six.

While this discussion touches on both small area and spatial forecast methods, only spatial methods are recommended for T&D planning. Table 3-2 lists some salient characteristics for the three major categories of small area load forecast.

Table 3-2
Comparison of Basic Categories of Load Forecast Method

Factor	Trending	Simulation	Hybrid
Basic Idea Behind the Forecast	Extrapolate past trend in weather-corrected annual peak load growth into the future on a small area basis	Model the processes driving growth: (1) Spatial expansion of mankind's use of land -- new homes being built, etc., 2) changes in usage of electricity and other energy sources as it is expected to occur into the future, Both on a small area basis	Mix trending and simulation in some way that hopefully combines more of the advantages of each than the disadvantages of each
Type of Area Format Used	Typically applied on an equipment-area basis since load histories are in that format.	Almost universally applied on a grid basis because of compatibility with land-use algorithms.	Has been applied in either equipment area or grid basis.

Table 3-2 (continued)
Comparison of Basic Categories of Load Forecast Method

Factor	Trending	Simulation	Hybrid
Typical Algorithms	Simplest: polynomial curve fit to past load histories (not a spatial method); Most effective: hierarchical recursive semisoidal curve extrapolation on a small area basis, controlled by a spatial growth statistical and pattern recognition analysis	Usually some combination of an "urban model" simulation of land-use changes a end-use/rate class load curve model of evolving per capita consumption patterns	Various algorithms that meld land-use and historical trend analysis: successful proven methods used spatial trending guided by long-term land use change data
Short-range accuracy for T&D planning	Fair to outstanding depending on method and the degree of success in correcting load transfers in historical peak data	Fair to very good depending on data and accuracy of calibration to the base year/historical data	Good to outstanding depending on data and accuracy of calibration to the base year/historical data
Long-range usefulness for T&D planning	Extremely poor to "not quite satisfactory" depending on method	Good to excellent depending on method	Good to very good depending on method
Useful for Integrated Resource Planning too?	No	Yes, depending on the type of end-use load curve model used, perhaps extremely useful	
Labor involved	Low to high depending on attention given to load transfers	High to extremely high	Medium to extremely high

Trending Methods

Trending methods apply some type of analysis to extrapolate recent trends in small area load growth into the future. As discussed earlier, the simplest approach is to extrapolate the trend of the last five to ten years of annual peak load on a small area (feeder or substation) basis into the future, using some sort of curve fit or similar approach such as multiple regression to fit to the historical data and extend it into the future. Numerous methods and programs have been applied in this manner worldwide. None are spatial methods, and all produce very high forecast error values compared to the best spatial forecast methods.

Spatial trending method also do an extrapolation of each small area's load, but in all cases, they perform some type of analysis of the combined set of load histories to divine patterns and relationships among individual small area load histories, and then forecast groups of small areas in one computation, (as compared to methods in the paragraph above, which serially apply the small curve fit to each small area, individually, in turn). The simplest and earliest spatial trending approach is multi-area Markov Regression, which simultaneously fits curves to a number of neighboring small areas' load histories in one computation, while putting constraints on their joint growth pattern.[28] This reduces error by about half compared to the best curve fitting on an individual small area basis. Today's most accurate trending methods take a spatial pattern recognition approach to do even better. While approaches vary, all perform a lengthy (compared to curve fitting) analysis and comparison of small area load histories as a first step, performing ten to one hundred times as much numerical analysis computation. An example is the INSITE algorithm the authors developed in 2006, which statistically determines how "growth looks" at various spatial resolutions (area sizes) and then fits curves to all small areas that minimize error against that entire set of multi-resolution statistics. Error five years into the future is about 1/5th that of the best non-spatial trending methods. This method is also the basis for the "trending part" of the most successful hybrid methods (see below).

The key advantage of trending, regardless of algorithm, is simplicity of application. It requires only historical load data (for example, peak demand data on feeders for the past ten years) which nearly all planners have readily at hand, and it can be applied on an equipment area basis (it directly forecasts feeder loads, or substation loads, etc., since it is extrapolating load histories for those. And while spatial trending methods are numerical complex algorithms, all trending methods are simple to apply: just input the historical data and run the program.

The chief disadvantages are, first, forecast accuracy. Non-spatial trending methods are notoriously inaccurate even just two to three years out in many cases. The best spatial methods are very accurate in the one to three year timeframe, but begin to display noticeable error beyond five years out. However, accuracy is not the primary forecast quality needed in long range forecasting, but trending still proves unsatisfactory.

In almost all long-range planning studies, a utility has a specific set of future conditions it wants to represent, known or expected major events or growth rates matching the corporate forecast, etc. What is needed is representative forecast—one representing a specific scenario. Spatial trending methods just do not have features that permit meaningful specific growth or major event characteristics to be represented.

Simulation Methods

Simulation methods apply some type of urban model to represent how use of land changes on a small area basis over time, then translate forecasted small area land use to electric load on a small area basis using "MV-90" type load research data. Until recently, almost all simulation-based spatial electric load forecast methods used some form of Lowry urban model, often called a linear urban model.[20,29,30,31]

These models are occasionally called Lowry-Gavin models: Gavin was an early improver of the computerized manner of applying the Lowry model. Developed in the 1960s and widely proven, the Lowry approach represents land use change as driven by growth centered at one of more regional activity, or employment, centers (often called urban poles) such as the downtown core

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[28] H.L. Willis, R.W. Powell, H.N. Tram, Long-Range Distribution Planning with Load Forecast Uncertainty, IEEE Transactions on Power Systems, Vol.2, No.3, pp.684-691, Aug. 1987
[29] I.S. Lowry, A Model of Metropolis, Rand Corporation, Santa Monica, CA
[30] J. Gregg et al, Spatial Load Forecasting for System Planning, in Proc. of the American Power Conference, Chicago, University of Illinois, 1978
[31] C. Ramasamy, Simulation of Distribution Area Power Demand for the Large Metropolitan Area Including Bombay, in Proc. of the African Electric Congress, Rabot, Apr. 1988

of a city or a heavy industrial area. As regional employment in these activity centers grows, demand for new homes, etc., also grows, with the demand centered geographically at those locations. Where growth ends up occurring, however, depends on evaluation of local characteristics in and around each small area—it must be easy to reach from the employment center, it must have a local profile matching "would make a good residential area," it should be close but not too close to major transportation corridors, and near but not too near existing retail shopping, etc., (what are often called "surround" or "proximity" factors). The resulting model of land use change balances demand and supply on a spatial basis to predict land use change, then (in electric utility applications) converts forecasted land use to electric load on a small area by small area basis depending on how much or what types of land use are forecast for each area (so many houses use this much power, so many acres of offices will use that much, etc.). A good review of the Lowry approach in general (not specific to the electric utility industry) along with a simple explanation of how they work can be found in Wikipedia.[32]

Spatial electric load forecast methods using that linear, Lowry-type urban models established an excellent track record in electric utility application from the late 1970s through the 1990s, particularly among utilities with rapidly growing suburban metro areas, such as those serving Austin, Houston, Dallas-Ft. Worth, Phoenix, Tampa and Orlando, Atlanta, Denver, Calgary, Portland, Salt Lake and other similar metropolises. In the period 1980 to 1995, the Lowry approach, implanted as several different computer programs, dominated T&D forecasting among those and similar utilities in the US. A major shortcoming of the Lowry approach from today's standpoint is that it was really designed only for "suburban metro forecasting". It is very good at what is often called "Greenfield" growth: forecasting how vacant land on the edges of large cities will develop into suburbs, office parks, shopping malls, etc. But it is not nearly as good at forecasting "Brownfield" growth: re-development in non-vacant areas with older, existing land-uses. For many electric utilities today, including quite a few of those metropolitan-area utilities that once used forecast programs based on the Lowry approach, this type of growth is now the major concern: old industrial areas are being converted to mid rise offices and condos; there is a slow, scattered, but steady replacement of two-story commercial with five story, etc, in developed parts of a city, and so forth.

As a result, not just for electric usage, but other basic infrastructure planning purposes (for example, water, roads, municipal planning) the Lowry approach has been replaced or augmented by newer growth simulation methods during the last ten to fifteen years. These newer methods still take something like a Lowry approach—they forecast land use change, they use look at both urban activity centers and local factors. But they usually do a much more complex analysis of all of those factors, and regional growth patterns. A common characteristic of newer approaches is some way of modeling "competition" or balance of inner-city growth with that in metro-peripheral, vacant land. At least four approaches have proven successful at simultaneously forecasting Greenfield and Brownfield growth, and balancing one against the other, although only two have been applied to electric forecasting:

[32] http://en.wikipedia.org/wiki/Land_use_forecasting

- The SLEUTH model[33] used by US Geologic Survey to predict how growth will change flooding patterns in urban areas applies three different urban models, including a Lowry type approach, and then applies a rule-based system to determine which model applies to which small areas, building up a composite forecast in this way.
- A method by Haining used for metro-area facilities planning in the UK works by spatially computing a "re-development pressure" in inner-city areas and balancing that against commuting costs for cheaper vacant land on the outskirts of a city.[34]
- A "redevelopment" overlay approach is used in Network's PowerGLF-S spatial electric load forecasting method, which is widely applied in Africa, the Middle East, and parts of the Pacific Rim. Here a Lowry approach forecasts suburban growth, a Haining-type approach the inner city redevelopment, and historical trending (this is a hybrid program) triggers an "entropy minimizing" optimization in Brownfield areas, to determine which of each type of growth actually develops.
- An agent-based approach that models statically the available choices in land-development was developed by Willis and Osterhus for Integral Analytic's LoadSEER program.[35] While it uses some Lowry concepts (urban poles, local factors) it does not apply them as in a linear urban model but looks at competition among factors in inner and outlying sites from a statistically many-buyers-have-different-needs perspective.

All four are relatively new but have established a good track record of forecasting Brownfield growth and balancing it against Greenfield development: SLEUTH on Baltimore and Colorado Springs; Haining's method on Birmingham and Glasgow, PowerGLF[36] on Pretoria, Johannesburg, and Adelaide, LoadSEER on Cincinnati, Charlotte, and Washington, DC. There seems little to choose among these approaches from an algorithm standpoint. SLEUTH, PowerGLF and LoadSEER gave nearly identical results when tested on Cincinnati and Washington. Regardless, all modern simulation methods, whether pure Lowry approaches or these newer algorithms, work with land use and customer data on a spatial basis, and work from within Geographic Information Systems (GIS) like GE's Smallworld or ESRI's Arc-Info. All make heavy use of the spatial data and analysis features of those systems. Land use data is generally obtained by "dumping" the utility's customer information system (CIS) data to small areas using the GIS, and by obtaining local municipal utilities zoning data in GIS format, etc.

Simulation methods give good accuracy in the 1 to 5 year time frame although the best spatial trending methods can match them in this timeframe. The advantage of a simulation approach regardless of method and algorithm is that the total amount of customer growth can be controlled to equal that the utility's revenue or marketing forecast (the corporate forecast) and the load curves used in the electric load translation can be taken from the utility's revenue and rate department's load research data. This means the resulting T&D forecast is completely consistent with the corporate revenue and "system" forecast, which is a highly recommended quality for every T&D forecast. Then, too, the better methods make it easy to represent future controlling events and factors well, too. The long-range representativeness of simulation methods is quite high.

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[33] http://www.ncgia.ucsb.edu/projects/gig/About/bkOverview.html
[34] R. Haining, Spatial Data Analysis: Theory and Practice, 2003
[35] http://www.integralanalytics.com/ia/ProductsServices/SpatialGrowthPlanning/LoadSEER.aspx
[36] http://www.netgroup.co.za/powerglf.html

Hybrid Methods

Hybrid forecast methods can be, strictly speaking, anything that attempts to combine elements of the trending and simulation approaches in order to combine the advantages of both while avoiding the disadvantages of either. The only successful approaches from a practical standpoint, however, have been trending methods that use limited amounts of land-use and urban modeling to improve their ability to forecast re-development and represent scenarios. Two recently-developed spatial forecast programs (PowerGLF and INSITE) as applied by Quanta are both hybrids combining land-use and historical trending, although they do so in quite different ways.

4
LOAD FORECASTING REQUIREMENTS

This chapter discusses load forecast requirements for traditional, current, and integrated resource planning applications; three "levels" of planning consideration that require increasing amounts of forecast detail in order to support good planning. It then moves to the major theme of the report: load forecasting for smart distribution systems, which is represented as a fourth level slightly beyond any of the other three. The requirements to accomplish load forecasting that can successfully support good planning of these future power delivery systems is presented

Traditional Distribution Planning Needs (1970s – 1990s)

Distribution load forecasting is the first step in distribution planning. Its purpose is to determine if the electric load on the power system will change in the foreseeable future, and if so, what the new load characteristics are likely to be. With this information planners can then determine if changes to the system are needed, and if so, what changes would be best, and when they should be made.

Much of the industry's current practice in distribution planning evolved from methods first developed and applied in the 1970s through 1990s. This traditional distribution planning was normally done on a peak load basis using computerized analysis and engineering tools of rather limited capabilities compared to those used today. However, the general approach used then is still followed. Equipment and facilities were planned against the peak (maximum) demand expected to occur. A tacit assumption in the planning, almost invariably true within the paradigm of planners at that time, was that if the system was capable of handling the peak load then it would work well at all lesser load levels.

Distribution systems are distributed systems; this means that there is a locational or spatial element to the planning. Individual components such as service transformers, laterals, feeders, substations serve specific service areas in their immediate location or neighborhood. A forecast of electric load and its timing is needed for individual components as well as the whole.

Interaction of demands at these locations is also a key factor planners must consider. It is often called coincidence or diversity of peak load. Electric demand at different locations may peak at different times so that the sum of the peak demands for all service transformers, for example, is far less than the peak load for the feeder that serves them. The same also holds true for a set of feeders and the substation that serves them.

Planners must plan ahead. Lead times are from one month (typical of service transformers) to five years (typical of substations) in the future, meaning that generally forecasts with a horizon ranging from one to five years ahead are needed. Within this timeframe, planners must make decisions as best they can and lock in their system planning projects.

Considerably uncertainty often exists about growth in different parts of the distribution system. New developments are announced but may be more "dream than reality". Growth depends on economic and political considerations that cannot be forecast. Publically-financed projects and growth initiatives may take longer to develop than expected. Electric demand projected for new buildings and institutions may not be exact. Planners address this with a multi-scenario approach, in which beyond the lead time, they study multiple forecasts: what might occur if certain developments did or did not occur. In this way they look at the options they might have to serve in the long term and can better determine what flexibility they need to include in their present (lead time plans).

Traditional Distribution Load Forecasting Requirements

To meet the basic distribution forecasting needs discussed above, distribution load forecasting methods evolved to provide the forecasted information shown in Table 4-1. Usually, forecasts were developed on a feeder basis, as the projected peak demand for each feeder. Some utilities broke feeders into three to six sections and forecasted the load in each. These forecasts did not include projections of load for service transformers—estimates of their loads were done only at the time the engineering was done when they were to be installed. Generally the short-range forecast needs shown in Table 4-1 were met with extrapolation methods, perhaps manually applied but generally computerized by the late 1980s, in which historical peak loading data on equipment (for example, feeder peak demands for the past five years) were trended into the future to provide a forecast. Coincidence was based on past observation (for example, diversity of peaks in this substation area has been 88%, so it will be estimated at 88% for the future, too). Long range forecasts were done using maps and load density estimates (for example, new subdivisions are 3.4 MW/sq. mi.)

Table 4-1
Forecasting Requirements for Traditional (Basic) Distribution Planning

Short-range forecast: one to five years ahead
• Peak demand in kW or MW
• Coincidence of load against substation and system peak (percent of peak)
• Spatial resolution: on an equipment basis
Long-range forecast: five to twenty years ahead, perhaps for several scenarios
• Estimates of spread of built-out areas geographically (what areas would develop)
• Estimates of range of load densities in these areas
• Spatial resolution: on a square mile or similar basis

Traditional Distribution Load Forecasting Methods

Forecasting methods used to produce traditional forecasts generally used extrapolation of past peak loads on an equipment basis. For example the past five to ten years of substation peak demands might be gathered, plotted, and used to fit a "curve" or straight line for projection of continuation of the growth trend. In the 1970s, this was done manually (with graph paper and pencil and rulers) at many utilities. Through the '70s and '80s more utilities began to use computerized methods, generally based on EPRI project RP-570 (year 1979-1980) results for regression-based fitting of polynomials to produce these forecasts.

Long range scenario forecasts were generally done on a map basis, using a "land use" approach, by literally coloring or plotting new residential commercial and industrial area onto a paper map and converting the results to substation and feeder load estimates using common load density expectations ("residential is typically 3.5 MVA/square mile", etc.) by class.[37]

Basic Modern (1990 – 2010) Distribution Planning Methods

In the late 20th century, planning needs throughout the power industry gradually evolved because utilities and regulators wanted to better utilize expensive equipment (increase utilization) and improve service quality (better reliability, better voltage control), and because the increasing capability of engineering software and hardware systems permitted more comprehensive analytical tools to be employed. It became more common to see planners asking for three additional forecasted variables:

1. VArs – the reactive load on the circuit, so that capacitors could be planned well to correct reactive flow and keep voltage high
2. Minimum load, often in conjunction with annual load factor – was often needed in order to plan losses to a minimum and plan system annual utilization best
3. Peak duration was used to size equipment just to the need – Long peaks meant equipment had to be more robust/have more cooling ability, etc.

Weather Normalization

In addition, in the 1980s and 1990s, it became more common for utility planners to insist that the historical loads they used in their extrapolations were weather-normalized. In some systems, typical variations between an extreme (hottest in ten years) and average summer can mean 12% different in feeder peak demands. Annual weather variations would thus play havoc with trending of peak loads. There might have been growth in demand this year, but with a mild summer it was masked by weather effects. Utilities would weather-normalize past feeder readings to a standard peak temperature and humidity (for example, 92°F at 80% humidity). Forecasts would then reflect a projection of peak demand at those normalized weather conditions. This both improved forecasting accuracy noticeably and led to more standardized planning. An example of this weather-dependency effect is shown in Figure 4-1 for the demand of a typical customer class of a US utility.

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[37] These methods are discussed in *Spatial Electric Load Forecasting*, 2nd Edition, Chapters 9 (basic trending), 11 (long-range scenario forecasts) and 17 (comparison of different methods)

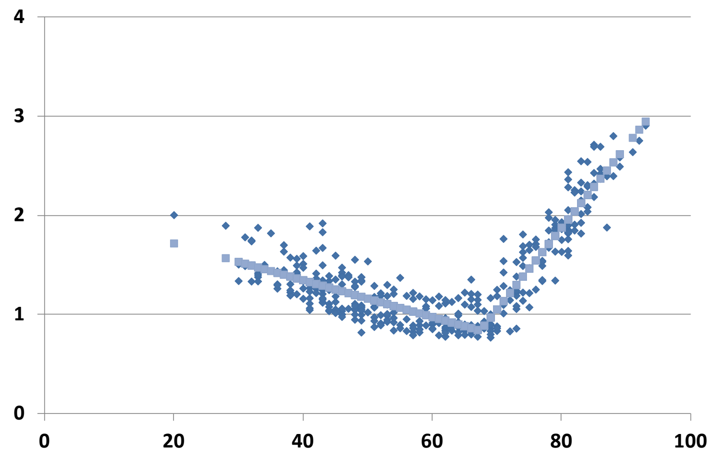

Figure 4-1
Load versus temperature model

In the 1990s, risk-based planning, often as a part of asset management approach to utility operation, applied weather normalization even further. The expected variation and probability of various levels of load, as a function of the “randomness” of weather, was forecast and used in risk-based planning of capacity. Altogether, these changes led to the basic modern distribution load forecasting needs shown in Table 4-2. There was generally no similar improvement in long-range planning and forecasting. During this period, focus was almost entirely in improving short-range (five year) planning, not on long-range planning.

Table 4-2
Basic Modern Forecasting Requirements for Distribution Planning

Short-range forecast: one to five years ahead
• Peak demand and minimum demand in kW+kVAr or MW+MVAr
• Duration of peak demand (hours, sometimes number of expected peaks/year)
• Coincidence of load against substation and system peak (percent of peak) under specific weather normalized conditions
• Weather sensitivity (kVA/°F or MVA/°F)
• Spatial resolution: on an equipment basis
Long-range forecast: five to twenty years ahead, perhaps for several scenarios
• Estimates of spread of built-out areas geographically (what areas would develop)
• Estimates of range of load densities in these areas
• Spatial resolution: on a square mile or similar basis

Forecast Methods for Basic Modern Distribution Forecasting Needs

Forecasting methods used to produce these basic forecasts generally evolved from those early computerized methods discussed in section 0. The most widely used method is trending—extrapolation of historical peak load data on a substation, feeder, or feeder section basis using regression fitted polynomials or other forms of equation. For example the past five to ten years of substation peak demands might be gathered and plotted. Then peak demands would be weather-normalized to a standard weather condition using regression, as a first step. Then, regression would fit the preferred equation to the weather-normalized peak data for the feeder or substation, and the resulting equation would be used to calculate forecasted loads for the future years.

Long range scenario forecasts were generally done on a map basis, using computers to replicate the traditional manually drawn area map studies. Areas representing square miles or quarter square miles were designated as to customer types in a computer database and an inventory by total system (and different portions of the system) summed to provide estimated customer counts of load projections for different T&D planning needs. Some software along these lines was given growth simulation capabilities using urban modeling concepts and models. The long range scenario estimates would plot new residential commercial and industrial area onto a printed maps and tables, converting them to loads using common load density expectations by class on a square mile basis and for substation and feeder areas.[38]

Integrated Resource T&D Planning

Integrated Resource Planning (IRP) involves mixing T&D system resources (system capacity) with demand side resources such as load control and Conservation Voltage Reduction (CVR), energy efficiency, conservation, and DG. Beginning in the 1980s, some utilities took this approach, at least in limited cases. Rather than spend money on adding new feeders and substations, the utility would spend money to encourage energy conservation and the use of efficient appliances (reducing demand), as well as put into effect good load control programs and CVR to reduce peak demand. To do IRP planning, planners needed more detailed information on customer type and end uses, including what contributed to peak demand (what appliances contributed to it, and how much) and what their timing was. An example of an end use model is shown in Figure 4-2. Early attempts in the 1980s and 1990s, like distribution planning itself at that time, focused on these factors only during peak times. However, by 2010 it was common to see 8760 hour models of loads used in such planning. This was accommodated by linking traditional distribution planning to Demand Side Management load curve models called end-use models. Economic justification for IRP plans, over strictly T&D expansion, often rested entirely on “lifetime cost” evaluations that often ran out to thirty years. Therefore, IRP created more focus on long range forecasting, at least to the extent of providing more information for analysis of lifetime energy, losses, and equipment costs.

IRP also required “market models” which were simply estimates of the incentives and financial adjustments to rates or utility subsidies that would be required to affect the demand-side resources. These were normally provided by utility rate and customer-side studies groups and allocated to distribution loads on a customer-content basis (for example, the load on this feeder is residential, the load on this commercial, the load on this one mixed 60/40, etc.).

[38] These methods are discussed in *Spatial Electric Load Forecasting*, 2nd Edition, Chapters 5 and 6 (weather normalization), 9 (basic trending methods), 12-14 (long-range scenario forecasts) and 17 and 18 (comparison of different methods).

Table 4-2 represents what might be called a "pre-smart distribution" baseline for distribution forecasting capabilities prior to the advent of the Smart Grid. Not all utilities did this level of forecasting in all cases, but in the authors' experience, almost any utility could, when and as needed, and many routinely did this type of forecasting, for example, Duke Energy and Pacific Gas & Electric (PG&E).

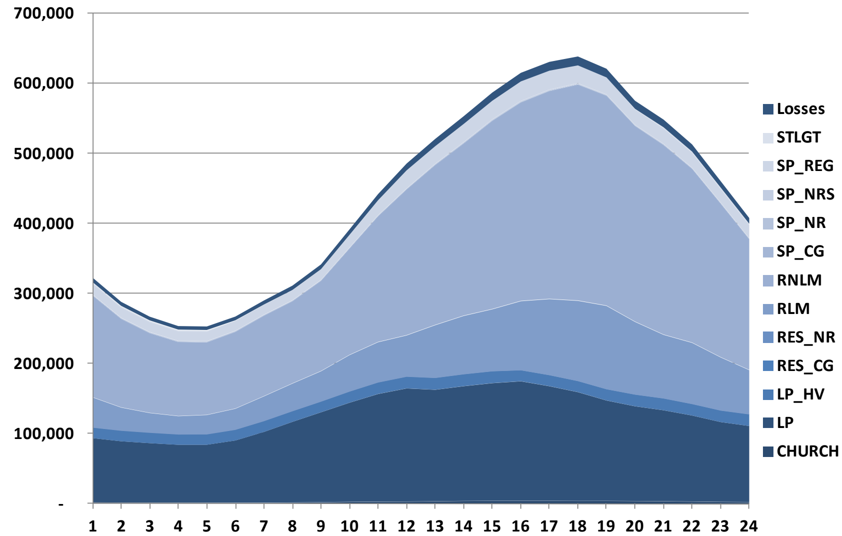

Figure 4-2
End use model

Forecast Methods for Integrated Resource Distribution Forecasting Needs

Forecasting methods used to produce IRP forecasts involved two "mergers" of forecast tools and method. The major merger involved merging distribution planning methods (see basic modern methods above) with DSM planning methods—specifically the customer load curve and end-use models used in customer and demand side planning by utilities.

A problem in making this merger was the DSM planning methods were customer-category based. They worked off of data about the number and type (residential, industrial) of customers. Most short range distribution forecasting methods did not use customer data. Thus, the short and long range forecast methods used for basic modern forecasting (Table 4-2) were merged, so that the short range planning methods used customer inventory data by substation and feeder, or at least had locations attributed by customer class. Then, potential or expected changes in load (on a customer class basis) were converted from the DSM planning to distribution loads. This was generally done with modified forms of the long-range planning programs (see discussion of forecasting methods after Table 4-3, above) to merge their load estimates with those of the DSM planning end-use load curve models. The expected changes were then used to adjust the short-range forecasted trends of peak load, etc.[39]

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[39] These methods are discussed in *Spatial Electric Load Forecasting*, 2nd Edition, Chapter 4 (end use load curve modeling), 15 (hybrid trending-customer class models), and 16 (energy and DSM modeling in distribution), and *Introduction to Integrated Resource T&D Planning*

Table 4-3
Modern IRP Forecasting Requirements for Distribution Planning

Short-range forecast: one to five years ahead
On a distribution equipment or area basis:
• Peak demand and minimum demand in kW+kVAr or MW+MVAr
• Customer composition by class (residential, commercial retail, commercial, industrial, etc.)
• Duration of peak demand (hours, sometimes number of expected peaks/year)
• Coincidence of load against substation and system peak (percent of peak) under specific weather normalized conditions
• Weather sensitivity (kVA/°F or MVA/°F)
• Spatial resolution: on an equipment basis
Allocation of the forecast above to:
• Customers by class (residential, commercial retail, commercial, industrial, etc.)
• By major end-use catagories (lighting, air conditioning, heavy equipment)
• By efficiency category
• On an 8760 hour basis
Long-range forecast: five to twenty years ahead, perhaps for several scenarios
For distribution planning:
• Estimates of spread of built-out areas geographically (what areas would develop)
• Estimates of by class (residential, commercial retail, commercial, industrial, etc.)
• Estimates of range of load densities in these areas
• Similar allocations of IRP factors as for short range forecasts (often same adjustments were used)
• Spatial resolution: on a square mile or similar basis
For IRP economics evaluation:
• Estimated lifetimes of energy efficiency measures and appliances
• "Market studies of customer preferences"

Smart Distribution Systems and their Forecasting Needs

Smart distribution systems will be taken here to include three sets of considerations that planners must accommodate in their forecasts and planning:

1. <u>Smart meters and energy consumers.</u> Smart meters, smart appliances, and "smart" energy consumers mean that homeowners, small and large businesses, and industry, can schedule and control energy use in ways not possible in the past. Among the changes expected are a general move toward dynamic scheduling of use to reasonably reduce cost when it does not cause inconvenience, and an ability of customers to accommodate easily utility requests for reduced consumption during emergencies or periods of low supply

availability, etc. Customer-side response, or demand response, will include methods very similar to load control of the past, but are much more likely to evolve to real-time pricing and "dynamic negotiation" systems that depend on pricing and incentives and customer response (often programmed in advance) rather than control.

2. DG, Distributed Energy Storage (DES), and new loads. Simultaneous with these smart changes on both sides of the utility meter, there are both new loads and new types of resources becoming available. New loads include PEVs: a recent survey of 500 utility chief executives indicated the industry expects 7% of energy sales to be due to PEVs by 2025.[40] Many homeowners and small and large businesses will also install solar energy systems, either as passive energy use systems such as solar (thermal) water and space heating systems, or photovoltaic (PV) generation. Some may also use DES facilities.
3. Smart distribution systems. Utilities will be able to operate systems that dynamically adjust to conditions of demand, system and equipment condition, and status, contingencies, weather, etc. These smart systems will monitor and control both their own equipment (feeder switching, protection and control, volt-VAr control, etc.) and customer demand and status (for example, the appliances and load operating at each customer's premises, the amount of that load that is potentially controllable, customer's current marginal cost for load reduction, etc).

Planning Needs in a Smart Distribution World

Overlap of corporate and distribution planning needs—Forecasting needs in a "smart distribution" industry begins by recognizing that distribution planning will gradually evolve to be much more integrated with corporate market planning. This will be a basic change that is expected in the role of distribution planning, one that effectively makes IRP much more mainstream and common throughout the industry.

Currently, many utilities such as Duke Energy, Southern California Edison (SCE), and PG&E, are planning customer marketing programs in which smart grid gives customers choices of service plans that include:

- Different amounts of demand response, for example, *"we'll discount your power if you allow us to control your thermostat within a five degree band"*
- On-site generation expectations by the utility, for example, *"we'll provide the first 6 kW of load, you take care of the rest" or "we'll buy all you can generate at market price minus our transportation fee"*
- Time-differentiated pricing, for example, *"we'll charge your PEV at night for only 4 ¢/kWh"*

These customer market programs are planned in many cases on a system or corporate basis, without detailed consideration of distribution consequences or targeting but with an expectation that distribution planners take them into account and use those capabilities well (programs after often justified on the basis of expected savings seen on the distribution system).

Utility distribution planner's forecasting needs in a smart distribution world can be broken into two parts:

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[40] 2012 Strategic Directions in the U.S. Electric Utility Industry http://bv.com/docs/management-consulting-brochures/2012-electric-utility-report-web.pdf

1. *Required to anticipate customer-side changes*, including those that will be created by the utility's corporate programs discussed above, as well as those that would happen anyway (for example, newer, smarter appliances). A utility customer base will see evolving changes in conservation, energy efficiency, DG, and loads (purchase of PEVs, wide screen 3D televisions, etc.). Irrespective of what planners or their utility may do to use smart technology, customers will utilize technology and make changes in a continuing effort to improve their lives. New appliances will be more efficient and smarter than in the past. People will gradually acquire more PEVs, etc. Some homeowners and businesses will install PV or other DG units, and perhaps DES. Others will be willing to respond to utility "green" or incentive-based marketing programs. On top of this, the utility will offer incentives and encouragement in certain areas that will accelerate some change. Planners must begin by anticipating these changes on top of the normal growth of demand due to increases in the customer base, etc. They will, of course, have access to their company's market models and customer load change analysis, but they will need load forecasting tools that can relate these to distribution loads, behavior, and coincidence.
2. *Required to analyze and plan the use of smart technology* by the utility. The second requirement area for planners is the information they need in order determine if and how they should use smart technology in their own plans for T&D system expansion and change. Some smart distribution planning requirements do not include any additional information as compared to pre-smart systems planning. For example, planning the use of smart recloser/sectionalizer systems to improve reliability can be done with the basic forecast information shown in Table 4-1. However, Volt-VAr Optimization (VVO)—both to improve voltage profile for power quality improvement and in order to practice sound CVR, requires information on load curve shape and composition like that for IRP (Table 4-3). Volt-VAr Optimization (VVO) can be considered as potentially a future "must-do" for all utilities so this forecast need is certain to become common. Finally, the utility's corporate customer market programs will in many cases include demand response programs that can and should be interfaced with and used as distribution resources, both to control and shape load (reduce peak at times to accommodate system capability limits) and improve power quality (reduce load at times to accommodate contingencies, increase load by operating DES at other times, etc.).

In general, IRP forecasting needs (Table 4-3) form a starting point for these needs, which are summarized in Table 4-4. The authors believe planners will need 8760 hour forecasts, or at least peak and minimum day load curve shapes, annual load duration curves, for most factors shown in this table.

Forecast Methods for Smart Distribution Forecasting Needs

Forecasting methods will most likely evolve from the most advanced IRP models used for distribution planning.[41] Currently, Duke Energy and PG&E use a Geographic Information System (GIS)-based forecast tool called LoadSEER[42] that accommodates all the needs shown above. The program has to be considered somewhat experimental, although it is in use at both utilities and several more, for example, PacificCorp, Kansas City Power and Light (KCP&L).

Table 4-4
Likely Distribution Planning Forecast Requirements in a Smart Grid World

Short Range Planning - 8760 hour forecasts by year for 1-5 years ahead
• Peak kW and kVAr weather normalized
• Weather sensitivity – kW and kVAr
• Energy efficiency sensitivity (kW and kVAr): difference between current load and the load if all appliances are of the most efficient type possible
• Controllable load (kW and kVAr) – how much can be controlled (turned off). Details about for how long and payback/rebound effects if any
• Customer side Generation (kW and kVAr): what is available at this hour
• Reliability need (amount of load (kW and kVAr) considered by customer as minimum need, at this hour
• Price sensitivity (marginal cost of load reduction at this hour)
• On an equipment basis (service transformers, laterals, feeders, substations)
Long-Range Planning – Annual forecasts for 6 to 20+ years ahead
• Peak kVA and energy use
• Controllable load
• Customer side generation

One of the areas that is introducing faster changes to how load forecasting is conducted in smart distribution systems is the growing penetration levels of DG. Utilities are treating this phenomenon in somewhat similar ways. An interesting example is Consolidated Edison of New York (Con Edison). In the case of Con Edison, prior to 2011 their practice was to ignore the potential peak load reduction due to DG output by adding back customer-site baseload DG to the customer's system load. This practice has been modified and currently, DG outputs are considered in system forecasts and load relief plans. This has allowed Con Edison to defer traditional load-relief capital projects. Furthermore, they have updated their planning criteria to consider available DG capacity. For instance, substations complying with N-1 and N-2 contingency design can include a reliable DG source as part of the total substation capacity as long as operating protocols are in place to back up the DG capacity.[43] Other utilities, such as and PEPCO Holdings Inc. (PHI) and Southern California Edison (SCE) have estimated the contribution that intermittent renewable DG to peak load reduction. For instance, analyses

[41] These methods are discussed in *Spatial Electric Load Forecasting,* 2nd Edition, Chapter 4 (end use load curve modeling), 15 (hybrid trending-customer class models), and 16 (energy and DSM)
[42] http://www.integralanalytics.com/ia/ProductsServices/SpatialGrowthPlanning/LoadSEER.aspx
[43] M. Jolly, D. Logsdon, C. Raup, Capturing Distributed Benefits – Factoring customer-owned generation into forecasting, planning, and operations, http://www.fortnightly.com/fortnightly/2012/08/capturing-distributed-benefits

conducted by PHI showed that a system with a PV peak output of 2 MW lowered the annual peak load of a distribution feeder by 0.44 MW, or about 22% of the PV capacity.[44] As proliferation of DG technologies continues it is expected that more utilities follow this trend and incorporate the contribution of conventional and renewable DG to peak reduction in load forecasting and distribution planning processes.

[44] S. Steffel, J. Romero Agüero, Integration Challenges of Photovoltaic Distributed Generation on Power Distribution Systems, 2011 IEEE PES General Meeting, http://www.smartgridinformation.info/pdf/4766_doc_1.pdf

5
AVAILABLE COMMERCIAL SOFTWARE TOOLS

This chapter discusses commercially available software programs and their abilities to develop detailed forecast models and to perform as forecast engines in executing and running those models. The software is needed to perform standard statistical analysis, to develop detailed multivariate forecast models, to handle large data sets and execute detailed mathematical models to produce both short-term and long-term load forecasts.

Forecasting Software Needs

The enhanced forecasting requirements that have been discussed in detail in Chapter 4 in most cases are dependent on the development of new and expanded load models for many different customer classes and subclasses. This will expand the amount of input data and computational power required for a forecast by at least an order of magnitude, and probably much more. Future load forecasting software must be capable of expanded data handling and number *crunching* abilities.

Traditionally distribution load forecasts for feeders and substations have been prepared without regard to individual customer classes but have been based on specialized local knowledge of the type of load and near-term growth expectations together with the previous historical kW or MW growth trend for a given feeder or substation. However, modeling of individual customer class loads is a major requirement for the enhanced forecasting requirements that have been suggested. Likewise, the development of reliable detailed data on both existing and future customer counts and loads throughout the distribution system will be necessary to support the enhanced forecasting capabilities. Much of this data is available to utilities these days through the use of Customer Information Systems (CIS), Outage Management Systems (OMS) or Advanced Metering Infrastructures (AMI), but it must be obtained and compiled in a form that will be useful in a forecasting system or software.

The enhanced forecast methods will involve both estimating future customer counts by class and then determining changes over time to the 8760 hour load shapes for each class of interest. In all cases, a variety of detailed customer data models will be required to develop inputs to the main forecasting engines to account for the multiple load controls, efficiency improvements, DER forecasts, new loads for example, PEVs, etc. The forecast tools must be able to estimate the customer count growth for each class by the use of econometric analysis, or obtain this information from load research analysis that is done by other tools and provided as inputs to the load forecast models.

In addition to customer counts, the other major need involves forecasting the future 8760 hour customer class load shapes or a more simplified representation that still can represent year round load characteristics. These load shapes will be developed based on smart grid controls, government or utility incentives and new load types. They will reflect new load growth patterns that differ from the past and thus cannot be predicted based on past data analysis. Future projections must be based on informed assumptions and expectations of promotional programs undertaken by the utility and local, state and national governments and will require external modeling of these new load patterns.

Software Modeling Requirements

A compilation of the types of forecast modeling requirements are listed below in order to pull together the issues identified in Chapter 4:

- Conventional Forecasting techniques
  - Regression analysis (trending)
  - Time-series analysis (more likely used for short term forecasting)
  - kW or MW short term and long-term forecasting
  - Diversity analysis (to relate coincident peaks to non-coincident peaks)
- Other analysis capabilities
  - Historical data statistical analysis
  - Correlation analysis
  - Fuzzy modeling
- Weather Normalization (multiple approaches have been used)
- Reactive power forecasting requirements will involve customer class models with kW and kVAR components, may need to be seasonal (that is, to capture residential AC load during the summer)
- DER forecasting (requires detailed DER models which are now included in many distribution software packages)
- Demand response (requires detailed customer end use models with and without DR)
- Advanced customer load controls (to model DMS, smart meters and smart loads requires detailed customer end use models)
- New load models for EVs and PEVs (smart charging and otherwise)
- IRP planning and forecasting (including DSM load controls, DER, CVR, efficiency projections, all separate inputs to the load forecast developed by other load research groups)
- 8760 hour end-use load models or at least weekday and weekend models for each month
- Market models and customer marginal cost for load reduction (used in separate models to estimate customer response to cost signals for price based customer load controls)

Planners will need load forecasting tools that can relate these many features to distribution loads, behavior, and coincidence. This will involve end-use model analysis for an expanded range of customer classes. Feeder load data will have to be augmented by detailed customer counts by class to allow for aggregation of the multiple load effects on any given feeder.

General Software Capabilities

Essentially all of the forecast packages should be capable of handling end-use models for multiple customer classes and subclasses. For most of the forecast software packages, these end-use load shapes will be developed by other analysis tools and imported into the forecast engines. These input load shapes are not necessarily fixed customer class loads but can be modified by multiplicative or additive factors, depending on the modeling assumptions.

Compromises may be required for many of the software packages regarding 8760 hour models. For example, full year models may be replaced by 24 typical 24 hour days, representing a weekday and weekend for each month of the year. Separate annual peak and minimum load shapes could also be used.

Commercially Available Software and Capabilities

This section presents a review of commercially available software tools that are either specifically designed for distribution load forecasting or that are designed for general purpose applications but are also utilized for load forecasting. This includes tools for STF, MTF, LTF, and spatial load forecasting. Some of the spatial load forecasting software tools have already been mentioned in Chapter 4, this section presents a review of their main features and capabilities. It is worth noting that a comprehensive and recently updated list of general purpose forecasting software[45] is presented in the Appendix of this document.

The following software programs are evaluated on their abilities to develop detailed forecast models and to perform as forecast engines in executing and running the models. These software tools have the capability to perform some or most of the needs previously reviewed.

1. **LoadSEER –** A comprehensive spatial load forecasting system, an enterprise tool rather than a load forecasting application, the most full featured system
2. **INSITE –** A MS Excel based spatial load forecasting tool. The core algorithms in its computational engine are developed in Visual Basic for Applications (VBA), it utilizes the statistical, database and plotting functions available in MS Excel
3. **FORESITE –** A small-area load forecasting software that includes a suite of products for system planning and analysis
4. **PowerGLF –** An Excel add-in that allows performing Geographically-based Load Forecasting (GLF) using a spreadsheet environment
5. **MetrixND –** Provides strong support for end-use model development but it is designed to work best with extensive ITRON meter databases, and is rather expensive
6. **SAS –** Also moderately expensive, requires significant statistical, regression and time series knowledge, and does not have preconfigured forecasting routines
7. **Forecast Pro –** More limited in modeling capability but does provide a variety of preconfigured and automated forecast routines for use, limited for large databases
8. **MATLAB –** A good general purpose data analysis platform, totally dependent on the user's statistical and forecasting knowledge, but otherwise rather flexible, somewhat limited in handling large databases

[45] J. Yurkiewicz, Forecasting Software Survey, www.analyticsmagazine.com

9. **Distribution system analysis software –** Some of the popular commercial distribution system analysis tools include additional modules or features with some forecasting capabilities. These tools however are more suitable for evaluating distribution system conditions (voltages, component loading) under various load growth scenarios calculated using a specialized load forecasting tool. This report discusses the features available in the following tools:
   a. SynerGEE Electric
   b. CYMDIST

LoadSEER

Supplier: Integral Analytics, Inc.[46]

This forecasting system is capable of the modeling requirements identified for smart distribution systems for medium to very large utilities. It is a comprehensive load forecasting system which combines the capability of using data from GIS, CIS, satellite imagery, load research, historical loads, customer class modeling, historical weather, etc. The system employs a hybrid forecasting approach which combines advanced statistical trending and rule-driven growth simulation analysis through spatial electric load forecasting. Planners can apply growth assumptions and rule sets for individual feeders or across an entire service territory, preserving old parameters for comparison and calibration. Core algorithms determine where growth will occur by applying rules about the distribution of land usage in a city or region. The rules have been developed from years of input from the utility industry, urban planning, and other infrastructure planning arenas and include water, highways, schools and municipal services, and environmental elements. Using three basic categories of rules—regional influence rules, local preference rules, and land availability rules—LoadSEER's simulation engine enables planners to run any number of growth scenarios created from sets of specific assumptions (for example, the economy, manufacturing plants, commercial retail, residential, transportation). LoadSEER is a self-documenting program that, during model-building, generation and calibration, saves parameters and map documents for review. LoadSEER is designed to accept a utility corporate forecast as an input, and strictly adheres to that aggregate level load forecast, on a customer class basis if available, as it more specifically allocates growth locally, assuring that the lower level forecasts are consistent with the top level corporate forecast. For every model generated, it produces tabular results for each planning area separately, and summarizes the change in load and customer profiles for each substation area. Models generated are output into the user interface via a "map document," which can be printed and saved.

This is not a forecast package that a user would use to develop forecast models or algorithms. At this time the package is customized by the developer for each specific user based on the data they have available and the scope of the forecast desired. Figure 5-1 shows a screenshot of LoadSEER's Graphic User Interface (GUI). Utilities that have experience utilizing LoadSEER include Duke Energy, PacifiCorp, Nashville Electric Service, Pacific Gas and Electric (PG&E) and Northern Virginia Electric Cooperative (NOVEC).[47]

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[46] http://www.integralanalytics.com/ia/ProductsServices/SpatialGrowthPlanning/LoadSEER.aspx
[47] G. Wolf, Planning 2.0, Transmission & Distribution World, Sep. 2008
http://tdworld.com/distribution_management_systems/planning_transmission_energy/

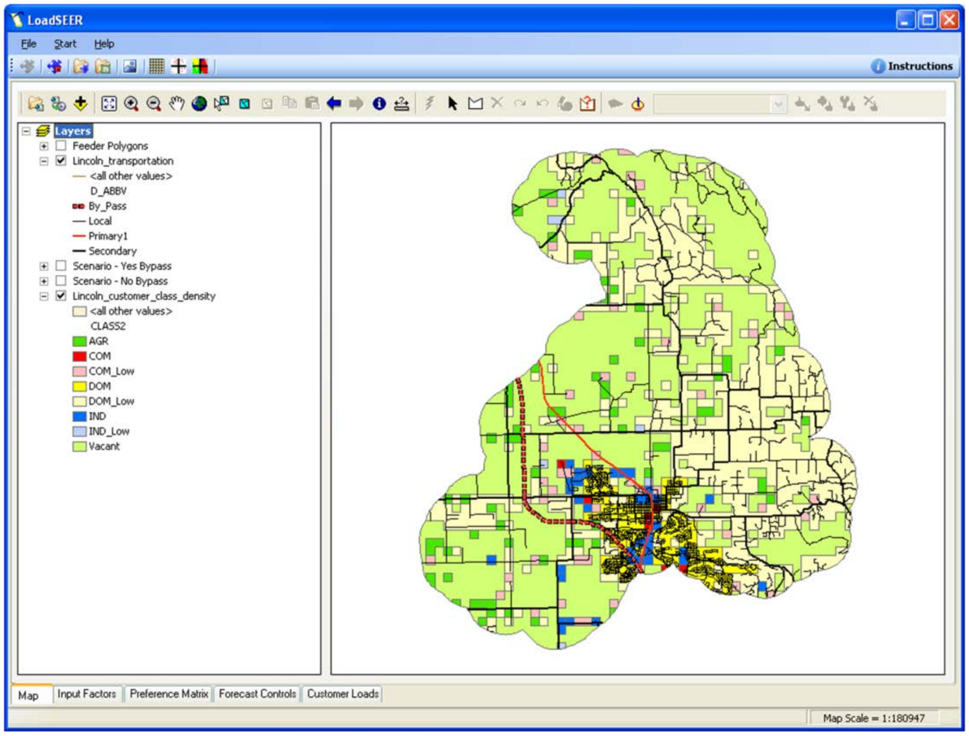

Figure 5-1
LoadSEER GUI

INSITE

Supplier: Quanta Technology LLC[48]

INSITE is a spatial load forecasting tool designed to trend load data in the mid and long term and combine with horizon year land use data for producing long-term forecasts.[49] The tool is designed to reconcile feeder level forecasts with corporate forecasts by employing a bottom-up and top-down analysis. Multilevel load and customer spatial load allocations are developed using a scheme that estimates surrounding regional influences at each level of aggregation. It is not currently designed for handling end-use models. INSITE is not a general purpose statistical or regression analysis tool. Econometric models and weather sensitivity effects are modeled separately and input to the forecast engine. Likewise, historical loads must be weather normalized separately as with most other routines. INSITE is not a forecast package that a user would use to develop customized forecast models or algorithms. At this time the package is customized by the developer for each specific user based on the data they have available and the scope of the forecast desired. The computation engine within INSITE was developed by using VBA and it uses MS Excel's functions to analyze, store, manipulate and graph data. Figure 5-2 shows a general description of the approach utilized by INSITE and its GUI. Small area load

[48] www.quanta-technology.com
[49] J. Romero Agüero, L. Xu, E. Phillips, J. Wang, T. Hong, H.L. Willis, Improvements in Spatial Load Forecasting Trending Methods for Distribution Planning Using GIS and Enterprise Data, DistribuTECH 2009, Feb. 2009

forecasts are aggregated using a bottom-up approach to create a wide area forecast, which is reconciled with the overall system forecast (for example, corporate forecast) and then adjusted on a top-down fashion to produce a final forecast. Utilities with experience utilizing INSITE include Madison Gas and Electric (MG&E).[50]

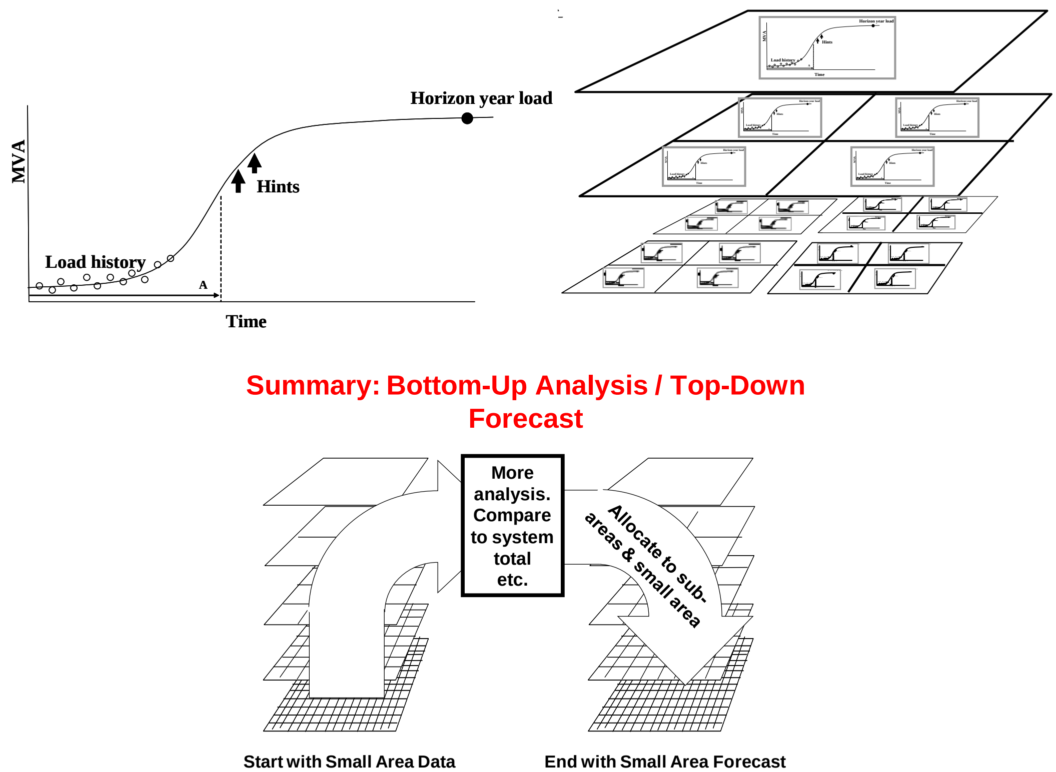

Figure 5-2
INSITE's approach and GUI[49]

FORESITE

Supplier: ABB[51]

FORESITE is a software tool designed for generating long-range small-area load forecasts that can be used to develop integrated strategic transmission and distribution expansion plans. FORESITE generates small-area load forecasts by simulating the effects and interactions of factors such as population growth, land use development, changes in customer classes, changes in electric appliance demand profiles, planned or existing roadways, waterways, lakes, protected habitats and low land areas. FORESITE's features include:[52]

[50] D.J. Barger, MGE experience with INSITE spatial load forecasting, 2011 IEEE PES General Meeting, Jul. 2011
[51] http://www.abb.com
[52] http://library.abb.com/global/scot/scot221.nsf/veritydisplay/9079090a9dd815e885256e2f006c5e25/$File/data%20sheet_Foresite_01-08-04.pdf

- Conversion of corporate level demand forecasts into geographic load forecasts
- Identification of usage characteristics of customer classes through end-use modeling
- Utilization of multiple-parameter growth assumptions to generate and compare T&D cost forecasts based on load projections
- Consideration of changes in usage by existing customers
- Evaluation of areas by customer density, class and various growth scenarios
- Modeling of interactions between customer classes
- Prediction of the impact caused by redevelopment efforts

FORESITE includes a suite of companion products: Network Planner, FeederAll, and Relinet. Utilities with experience utilizing FORESITE include Nashville Electric Service,[53] BC Hydro,[54] and Arizona Public Services (APS).[55]

PowerGLF

Supplier: NETGroup Solutions[56]

PowerGLF is an Excel add-in that allows performing Geographically-based Load Forecasting (GLF) using a spreadsheet environment. PowerGLF's functionalities include:

- Managing of load forecast supportive input data (for example, land use densities, daily load profiles, growth percentage, etc.)
- Long term (20 year) load forecasting per load zone
- Forecast methods
  - Land use based
  - Customer based
  - Custom growth curves
  - Percentage growth
  - Trending
  - Fixed increment
- Diversified summation of the forecasted load over various reporting levels
- Ability to complete multiple forecasts for smaller areas and summate results in a single forecast
- Creating of different load forecast scenario~Rs
- Creating of different load forecast scenario~Rs
- Allocation of loads to current and planned network
- Drag and drop load on to summation hierarchy

[53] L. Leech, J. Burke, NES Tackles Circuit Reliability, Transmission and Distribution World, http://tdworld.com/mag/power_nes_tackles_circuit/
[54] A. Hussain, Distribution Long Term Planning at BC Hydro, Edison Electric Institute, Fall Transmission, Distribution and Metering Conference, Oct. 2009
[55] B. Urcuyo, FORESITE at APS, ABB Annual User's Group Meeting, Aug. 2007
[56] http://www.netgroup.co.za/powerglf.html

- Sub-class library
  - Enables management of customer groups
  - Used to associate profiles and growth curves to specific customer groups.
  - Forecast specific attributes can be set per sub class
- Average load profile definitions
- Growth curve definitions
- Load zone forecasts
- Load summation

Utilities with experience utilizing PowerGLF include Eskom (South Africa).[57]

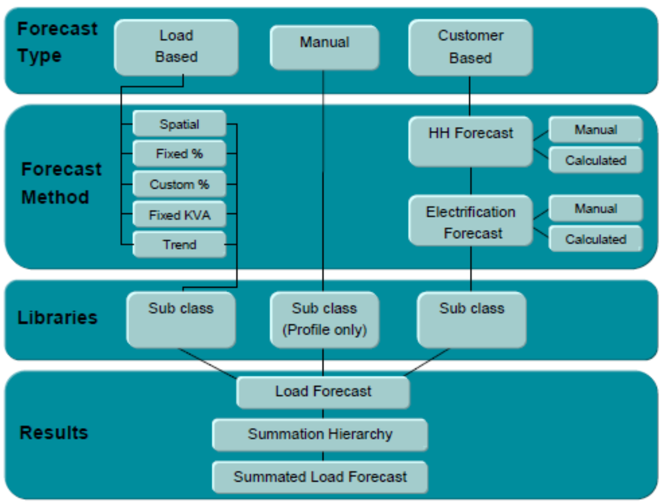

Figure 5-3
PowerGLF's high level description[56]

Forecast Pro

Supplier: Business Forecast Systems, Inc.[58]

This tool can be used to build traditional load forecasts based on multiple customer classes but has no built-in intelligence for simulating spatial load growth. It comes in several versions:

- Forecast Pro XE – a stand-alone desktop tool, offers time series methods, promotional modeling, causal modeling (dynamic regression), the ability to define and reconcile hierarchies, and capable of forecasting up to 100 items at a time. To aid the experienced forecaster, it provides a full range of menu-driven custom modeling options along with detailed diagnostic displays. ($1,300 – single license)
- Forecast Pro Unlimited – offers the same capabilities as Forecast Pro XE except it provides enhanced documentation trail support more useful when a team of individuals is working on the forecast together all making changes, or for when tracking of multiple adjustments and overrides is important. ($5,000 – single license)

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[57] http://bits.eskom.co.za/dtechsec/distribu/tech/GUIDE/DGL_34-1284.pdf
[58] http://www.forecastpro.com/

- Forecast Pro TRAC – offers all the features of Forecast Pro Unlimited with several additional capabilities. The one capability, Team Forecasting, might be most useful to a large forecasting group with different geographical divisions. This feature supports automatic consolidation of forecasts developed by separate planners. This important for keeping track of individual customer class data across the whole forecast. Accuracy tracking also could be useful.

Features common to all versions:

- Exponential smoothing and linear and quadratic regression, together with Growth (S-curves)
- Box-Jenkins time series analysis
- Dynamic regression (Forecast Pro XE only) using leading indicators
- Event Models – to factor in special new developments
- Multiple-Level Models – allow data aggregation into groups that can be reconciled using a top-down or bottom-up approach to produce consistent forecasts at all levels of aggregation
- Automatic modeling through built-in Expert Selection

All three Forecast Pro systems have the same technical and analytical capabilities but differ in user interface and support of forecast team collaboration. They may be used for both regression and time series analysis. This produce was originally developed and designed for businesses with large numbers of retail products to track, including their sales for multiple regions, inventories in multiple locations, etc. For electric load forecasting purposes, this tool may suffer from handling huge data sets such as hourly weather data over a forty year period potentially used for weather normalization, or other large data handling requirements.

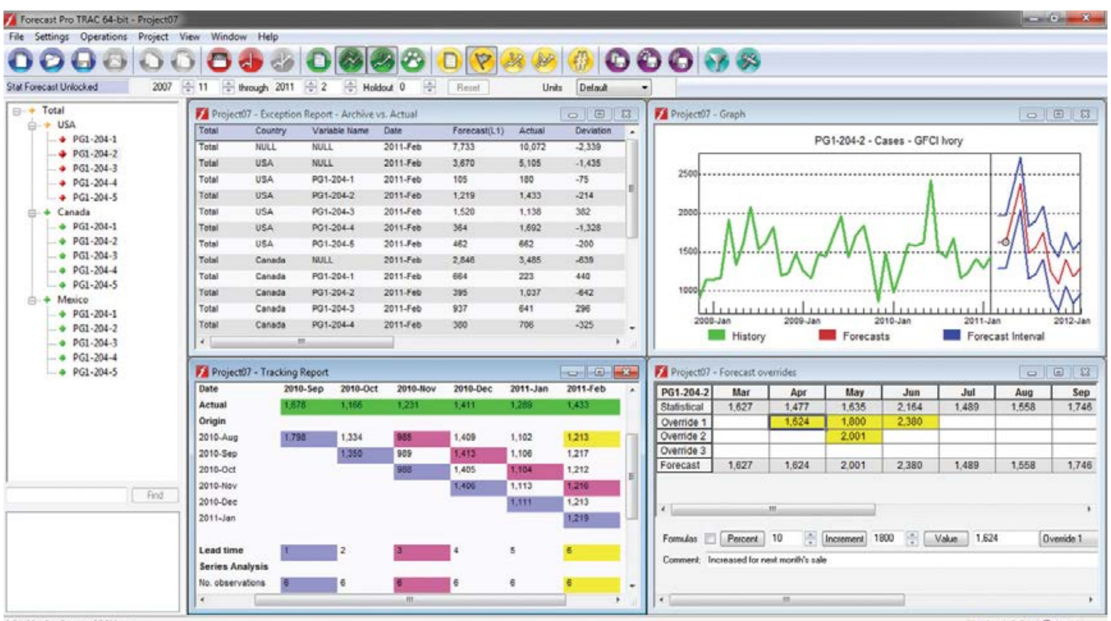

Figure 5-4
Forecast Pro[59]

[59] http://www.forecastpro.com/products/overview/TRAC.htm

SAS

Supplier: SAS Institute Inc.[60]

As a statistic software package, the Base SAS software provides a wide range of capabilities to support regressions and time series analysis that are the essential building blocks for traditional load forecasting. SAS Enterprise Guide provides a Graphic User Interface for a point-and-click, menu- and wizard-driven tool to enable analytics and reporting available to general users. In addition, SAS provides strong training support for users at additional expense.

SAS Forecast Server uses its SAS Forecast Studio GUI to surface the large-scale automatic forecasting power of SAS High-Performance Forecasting along with the sophisticated time series data preparation and time series modeling features of SAS/ETS® software. This tool can be used to build traditional load forecasts. Its econometric analysis capabilities can also support the modeling requirements identified for smart distribution system as described previously. It has two components:

- SAS Forecast Server – This component generates large quantities of forecasts quickly and automatically without the need for human intervention unless so desired. The software automatically chooses the most appropriate forecasting model, optimizes the model parameters and produces the forecasts. This tool can select special events such as holidays to aid the forecasting process. In addition, planners can test what-if scenarios and determine how different load growth patterns are likely to affect future demand.
- SAS/ETS Software – The time series data management capabilities of SAS forecasting software is mainly supported by this component. SAS/ETS offers a broad array of econometric, time series and forecasting techniques for improved strategic and tactical planning. The affect of "market model" associated factors such as customer demographics and user profile, consumer response to economic conditions, demand response programs and government/utility incentives have on the future demand change can be analyzed using this tool in order to provide load forecast in smart distribution systems.

The supported forecasting and time series methods include:

- Trend extrapolation; exponential smoothing; Winters' method (additive and multiplicative); ARIMA (Box-Jenkins).
- Dynamic regression.
- Automatic outlier and event detection.
- Time series decomposition and seasonal adjustment.
- Spectral and cross-spectral analysis for finding periodicities or cyclical patterns in your data.
- Similarity analysis for sets of time series.
- Monte Carlo simulation for scenario forecast.

[60] http://www.sas.com/technologies/analytics/forecasting/index.html

MetrixND

Supplier: ITRON[61]

ITRON has produced a variety of forecasting tools that provide comprehensive but more costly forecast solutions. Some of the advanced features are designed to integrate with data recorded from ITRON metering systems. Additional data structuring would be required to make use of non ITRON data. These tools have no built-in intelligence for simulating spatial load growth.

MetrixND can be used for various forecasting processes, including short-term and long-term energy and demand forecasting, price forecasting, individual customer load forecasting, financial forecasting and weather normalization. It is designed to develop dynamic and integrated models at monthly, daily and hourly levels. MetrixND is used by about 150 utilities and energy companies in nine countries. Designed to take advantage of advanced Windows capabilities, MetrixND offers an intuitive user interface with drag-and-drop architecture. It provides a range of modeling techniques including neural networks, multivariate regression, ARIMA and exponential smoothing. Evaluation graphs, diagnostic statistics and reports are available to assist in developing and analyzing forecasts. It is designed for quick evaluation of alternative models and to select the model that works best for the data provided.

A strength of Metrix ND is that it is designed for modeling end-use loads and readily embodies end-use trends into a monthly econometric forecasting framework. Itron has worked with the Energy Information Administration (EIA) to embed their latest equipment saturation and efficiency trend forecasts in these models. Energy Forecasting Group members (organized by ITRON) receive regional versions of the SAE models (MetrixND project files) and the associated regional databases. Residential and commercial electric and gas SAE models are available to members along with a technology option for electric residential appliances including lighting. Another strength for Metrix is organized user training at additional expense. There also is support through a user's group and an annual user's conference.

Other Metrix tools include:

- Forecast Manager is a front end tool that uses the MetrixND forecast engine to manage and track the data for doing comprehensive sales analysis and forecasting
- MetrixIDR Retail for retail forecasts for day-ahead market planning
- MetrixIDR System Operations for supporting short-term energy load and price forecasting
- MetrixLT for long-term modeling approaches that incorporate end-use structure for monthly econometric models

AleaSoft

Supplier: AleaSoft Energy Forecast[62]

This software consists of three different tools for STF (AleaShort), MTF (AleaMid), and LTF (AleaPlan). The tool utilizes a hybrid model that combines Artificial Neural Networks, SARIMA and regression analysis. The resulting model is an ANN with a SARIMA structure and an

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[61] https://www.itron.com/na/productsAndServices/Pages/MetrixND.aspx
[62] http://www.aleasoft.com/1_productos_energy_load_price_forecasting.html

adaptive scheme that adjusts the parameters of the ANN on an ongoing basis. Explanatory variables included in the model are related to calendar, weather conditions, temperature thresholds and socio-economic evolution. Utilities with experience utilizing this software include Enel, EDF, Iberdrola, e-on, and Endesa.

MATLAB

Supplier: MathWorks[63]

MATLAB (Matrix Laboratory) is a numerical computing environment and fourth-generation programming language. MATLAB allows matrix manipulations, plotting of functions and data, implementation of algorithms, creation of user interfaces, and interfacing with programs written in other languages, including C, C++, Java, and Fortran.[64] MATLAB is a programming environment for algorithm development, data analysis, visualization, and numerical computation. MATLAB can be used in a wide range of applications including financial modeling and statistical analysis, and thus is generally suitable for forecasting. It is a tool familiar to many engineers and scientists in industry and academia.

MATLAB's many data analysis functions, statistical modeling and visualization features can be used to develop and implement customer end-use models, weather normalization routines, regression and time-series model building. However, the methods used in applying all of these features to load forecasting will need to be developed by the user. It does not contain automated model building features that are found in some other software. This can be both a strength (not being restricted by prepackaged routines) and a weakness (the user may need additional support modeling support). Every aspect of the forecast process must be developed by the user from scratch. There are various optional modules in MATLAB that can provide essential functions to support building the load forecast process using historical, seasonal, day-of-the week, and temperature data; they include the Econometrics Toolbox, Financial Toolbox, Statistics Toolbox and the Neural Network Toolbox.[65] All these toolboxes have additional capabilities besides forecasting and include some GUI features. However, as a general purpose tool, it has no user interface designed specifically for load forecasting purposes.

It is worth noting that Matlab has made available for download a webinar, presentation, and M-files (basic programming files for utilization with Matlab) on "Electricity Load and Price Forecasting Cases Study".[66] This case study focuses on load and price STF using non-linear regression models based on ANN and Bagged Regression Trees, Figure 5-5 shows the load forecast model architecture. The case utilizes hourly data from NEPOOL provided by ISO New England.

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[63] http://www.mathworks.com/discovery/load-forecasting.html
[64] http://en.wikipedia.org/wiki/MATLAB
[65] http://www.mathworks.com/products/
[66] http://www.mathworks.com/matlabcentral/fileexchange/28684-electricity-load-and-price-forecasting-webinar-case-study

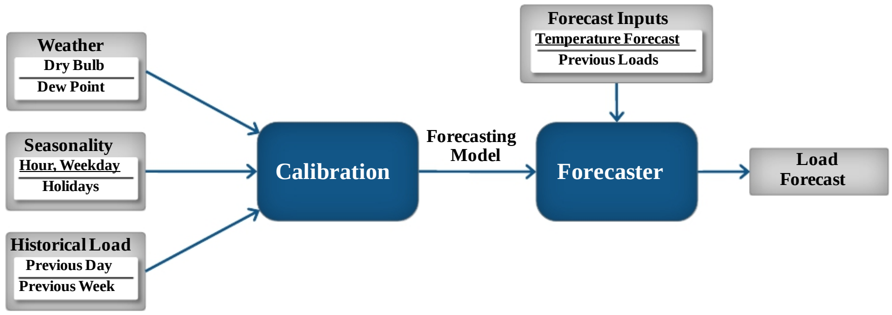

Figure 5-5
Load forecast model architecture[66]

Distribution System Analysis Software

SynerGEE Electric

Supplier: GL Group (Germanischer Lloyd)[67]

SynerGEE's forecasting tool applies expected growth trends to areas of interest (sections, meters, feeders, zones, substations, regions, etc.) in distribution models, and operates in the five load models in SynerGEE: distributed, spot, large customer, project and speculative. Load growth can be applied to certain sections of a feeder by overlaying spatial growth polygons over the feeder sections that expect higher rates of load growth. The load is allocated to the feeder edges where growth is expected from new developments and road projects.

Different from many other forecasting tools aforementioned, SynerGEE's forecasting tool is a distribution model based tool; it allocates growth to the loads instead of entire feeder. The tool requires the expected growth on the areas of interest to be known beforehand, and then allocates the expected growth to different customers in the area. This tool does not provide statistic capabilities to support trending analysis from the historical records; this tool does not support the modeling requirements identified for smart distribution system such as load model and market model, either. Therefore, SynerGEE's forecasting function is more of a supporting tool for utility planners instead of the load forecasting functions that considered and discussed in this document.

[67] http://www.gl-group.com/en/powergeneration/SynerGEE_Electric_LoadForecasting.php

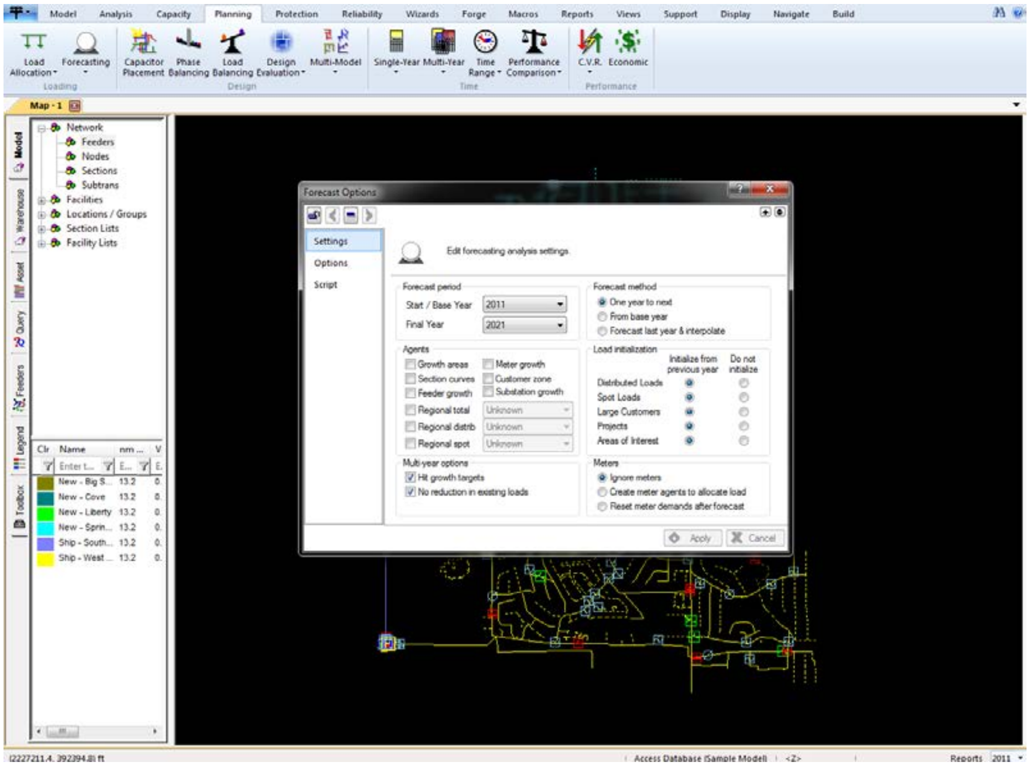

Figure 5-6
SynerGEE

CYMDIST

Supplier: Cooper Power Systems[68]

As distribution analysis software, CYMDIST is designed for planning studies and simulating the behavior of electrical distribution network under different operating conditions and scenarios. The Network Forecaster module is the add-on to the CYME software designed to assist in managing and planning expansions and changes over time on distribution network. The Network Forecaster module allows creating, viewing and modifying time-dependent projects/scenarios in a selected period such as addition of loads at a given date (year, month or day). Similar to the forecasting modules in other distribution system analysis software, this function aims to help structure the distribution planning projects. However, there are no load forecasting capabilities included in this module. The expected load growth or change, that is, the module input, needs to be identified by planners first utilizing a load forecasting tool.

[68] http://www.cyme.com/software/cymdistforecaster/

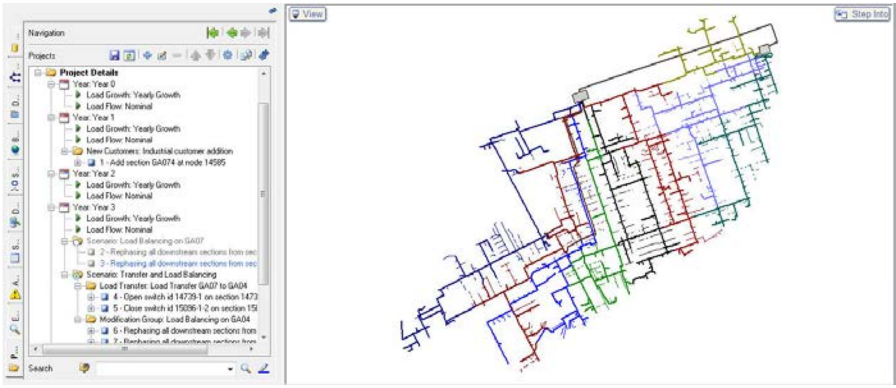

Figure 5-7
CYME Network Forecaster

Other Load Forecasting Tools

There are numerous other load forecasting tools, most of them have been developed for STF or MTF or specialized applications, and do not have spatial (small-area) load forecasting capabilities. These tools have been developed by specialized forecasting services firms, independent consultants, research organizations, universities, etc. A quick search on the internet can provide hundreds of results including numerous freeware downloadable tools. Some examples include:

- TeslaPower:[69] It is a menu-driven system for energy load analysis and forecasting that consists of a forecasting module and a weather correction module
- Demand Analysis and Planning (DAP):[70] It is a software tool designed to forecast demand and load and to draw up Demand Side Management (DSM) actions. DAP includes four applications: 1) simple trend forecast, 2) sector trend forecast, 3) customer trend forecast, 4) DSM forecast
- e-LoadForecast:[71] It is an online load forecast service that delivers load forecasts for client-specific electric or gas load data. The forecasts can be generated for different horizons and various resolutions (hourly or sub-hourly), and are run by an engine made up of multiple models based on artificial neural networks, fuzzy logic and evolutionary computing/genetic algorithms

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[69] http://www.teslaforecast.com/TeslaModel.aspx
[70] http://www.systemseurope.be/products/dap.en.php
[71] http://www.prt-inc.com/e-LoadForecast.aspx

6
CASE STUDIES

A series of analyses and simulations were conducted to investigate how the proliferation of selected technologies and concepts would impact load forecasting of smart distribution systems. The technologies and concepts of interest for this study are Plug-in Electric Vehicles (PEVs), Distributed Generation (DG), Net Zero Energy (NZE), Demand Response (DR), and energy efficiency programs. Finally, additional analyses and simulations were conducted for reactive power forecasting. This section presents the results of these investigations, including a description of the supporting methodologies and assumptions utilized in these analyses. The objective of these case studies is to illustrate some of the challenges that utilities are starting to experience in the context of spatial load forecasting as a direct consequence of the distribution system evolution and implementation of the Smart Grid concept. As previously discussed, the demonstrations are focused on spatial load forecasting since this is considered to be the key tool for modern and future distribution systems planning, and on LTF, which arguably represents the most challenging forecasting situation given the uncertainties to consider and manage. The assumptions utilized in these studies are not exhaustive, the point rather being to demonstrate at a conceptual level how these issues could be tackled utilizing modern spatial load forecasting tools. The analyses where conducted by utilizing INSITE.

The simulations where conducted for a test service territory equivalent to that of a small size US utility. The service territory was divided in a grid of small areas (uniform squares) with individual surface of 1500 ft x 1500 ft, similar to that shown in Figure 3-4 (right), and includes a mix of different land uses (residential, commercial, industrial, etc). The purpose of the demonstration is to forecast annual peak loads for each of the small areas for the next 20 years. The algorithm utilizes two main inputs, historical load data (five years) and horizon year loads to calculate S-curves for each small area; this is conceptually shown in Figure 6-1. Each small area has a land use category that is defined by the local urban development government agency and that may evolve over time. Each land use category has a load density associated with it; this load density can be calculated by analyzing utility data. Future land use categories and their corresponding load densities are used to calculate the horizon year loads used in the forecast. Moreover, the algorithm utilizes a total load forecast for the area or service territory under study, typically the corporate load forecast. This total forecast, although also complex to calculate, it is relatively simpler to estimate than small-area spatial load forecasts since it exhibits slower dynamics and less volatility. The algorithm utilizes these inputs and a bottom-up/top-down approach to coordinately adjust the parameters of the individual small area S-curves in such a way that allows matching the total (corporate) load forecast. The algorithm could also utilize "hints" in this process, these hints are likely developments that are expected to drive load growth in the area, for example, distribution planners may know that a new shopping center will be built or that a new factory expects to start operations next year. For simplicity these hints have not been considered in the demonstrations.

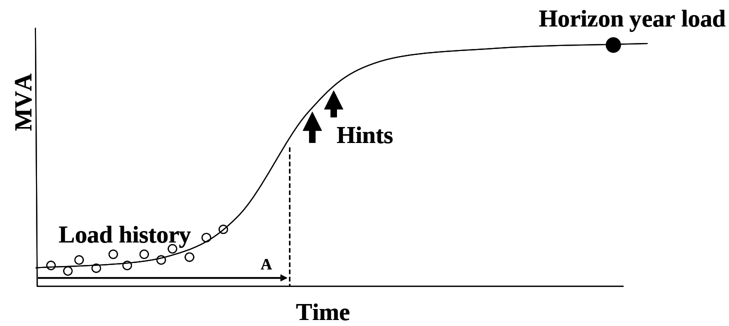

Figure 6-1
Small area load forecast

Analyses and Assumptions

This section describes the key aspects of the analyses, assumptions and simplifications utilized for each smart technology scenario. This discussion has the purpose of illustrating in general terms some of the previous work and considerations that a distribution planner would need to make to prepare the data required for a spatial load forecast involving smart grid technologies. Evidently, these analyses, assumptions, and simplifications will depend upon the information and data available, and could involve very detailed studies that are out of the scope of this discussion. The key aspects of the analyses are:

- This set of demonstrations aim to show how to apply spatial based load forecasting algorithms to implement load forecasting with emerging smart distribution technologies. In these analyses a both bottom-up and top-down S curve fitting methodology was utilized
- The spatial load forecast has been separated into: a) forecast for loads associated with or driven by smart distribution technologies, and b) forecast for conventional loads
- Historical load data associated with smart distribution technologies have been artificially generated for the first five years and then a spatial load forecasting algorithm has been applied to forecast the next 15 years

The spatial load forecasting algorithm utilized in these analyses relies on hierarchical and coordinated S-curve trending. Therefore, it is necessary to properly treat the historical load data. Historical load data for most utilities nowadays does not include a significant portion of load associated with smart distribution technologies. Smart distribution technologies will tend to modify traditional load growth patterns, which are modeled by the S curve (Figure 5-2) used by the load forecasting algorithm employed in the simulations[49]. For example, the adoption of PEVs may cause a fast load growth, increase the S-curve slope and bias its parameters, if this is not adequately considered it would lead to inaccurate load forecasting in the long term. As a result, directly using the historical load currently available to forecast the future total load would not be suitable. Hence, in order to avoid these types of issues, in this demonstration forecasted load was divided into conventional load, which is expected to follow the traditional growth trend shown from the historical load data, and smart distribution load, which does not have sufficient historical load data yet.

It is worth noting that the availability of historical load for smart distribution technologies is vital for a reliable forecast. If the data is either not available or insufficient and the algorithm is directly applied to obtain a load forecast, it will end up randomly predicting the "take off" timing for the S-curves of different small areas.[72] For this demonstration, the authors generated five years of hypothetical load data for smart distribution technologies. In real life applications, utilities may need to use their own envisioned deployment rate of these technologies and generate expected load profiles for long term load forecasting.

The final year load data (horizon year load) utilized by the algorithm is obtained from the analysis of load densities of future land use. Land use information can be obtained from local government projections and land-use planning databases,[73] and can be classified in numerous categories such as residential, commercial, rural, etc. In order to obtain the smart technologies load data required for the analyses land use categories are not modified, only load densities are changed.

Table 6-1 shows the land use types used in this demonstration as well as the percentage of the area under study that is classified under each land use type for the base year and the horizon load year. In an actual load forecasting implementation land use types will be specific for the service territory of the utility under study, that is, other land use designations may be used, for example, "beach", "highway", etc. Proliferation of smart grid technologies is only assigned to residential, industrial, commercial, and institutional land uses. Other land uses such as "Extractive", "Communication", "Transportation", "Agriculture", "Parks", and "Natural" are excluded.

[72] Since every small area would have zero smart distribution load, there would not be enough additional information available to estimate the different "take off" times of each small area

[73] For instance, the California Land Use Planning and Information Network (LUPIN) http://ceres.ca.gov/planning/countylists/spatial.html has a very comprehensive database of state-wide land-use

Table 6-1
Type of Land Use for Base and Final Year

Type of Land Use	Land Use (%)	
	Base Year	Final Year
Industrial / Business	1.49	2.90
Extractive	0.64	0.22
Commercial (Retail & Services)	2.41	3.72
Institutional / Government	1.67	1.64
Rural Residential	2.13	3.18
Low Density Residential	8.10	11.57
Medium Density Residential	0.54	1.20
High Density Residential	1.51	1.88
Communication / Utilities	0.42	0.40
Transportation	9.21	9.47
Agriculture / Vacant	40.00	30.08
Parks / Outdoor Recreation	3.42	4.08
Natural / Woodland / Water / Other	28.46	29.64
Total	100.00	100.00

Assumptions for PEVs

PEVs can charge at different levels, demanding different power from the grid. It is assumed that, at residential premises, half of the PEVs charge at 3.3 kW level (approximating PEV level 2 charging) and the other half of the PEVs charge at 1.8 kW level (approximating PEV level 1 charging).[74] As a result, the load density of PEV charging for residential customers is calculated based on an average charging level of 2.55 kW per PEV (that is, the average of 3.3 kW and 1.8 kW). Moreover, it is assumed that PEVs charge at a higher level at commercial/industrial/institutional charging locations, with an average demand of 5 kW.

In addition to the difference of the PEV charging levels, PEV charging demand also varies among different hours of the day. Typically, residential customers have more PEV charging in the evenings and at nights, office buildings experience more PEV charging after the morning commute and lunch hours, and commercial customers may have PEV charging spread out throughout the day.

[74] J.Romero Agüero, P. Chongfuangprinya, S. Shao, L. Xu, F. Jahanbakhsh, H.L. Willis, Integration of Plug-in Electric Vehicles and distributed energy resources on power distribution systems, in Proc. of 2012 IEEE International Electric Vehicle Conference (IEVC), Mar 2012

As previously indicated the algorithm aims at forecasting annual peak loads for each small area. The system peak hour may vary for utilities at different geographic regions and with different customer mixes and consumptions patterns. The authors' previous project experience analyzing utility data has shown system peaks occurring between 3 PM and 5 PM. In this demonstration case, 4 PM was selected to be the system peak hour.

It is worth noting that when the smart distribution technologies reach a very high penetration rate, system peak load may appear at a different time. For example, penetration rates of PEV exceeding 50% may shift the system peak to a later time when significant residential PEV charging coincides with traditional residential peak loads. Although it can be argued that this scenario may occur in the next 20 years, market indicators show slower proliferation of PEVs than originally expected. For this reason and also for the sake of simplicity this more detailed scenario is not discussed in this case study.

In previous studies[75] the authors used the 2009 National Household Travel Survey (NHTS) database to extract the vehicle usage patterns for different trip purposes such as commute trips and errand trips, and different geographic regions such as urban areas and non-urban areas. In addition, the studies also extracted the statistical distributions of trip end time (corresponding to the PEV charging start time) and the distance traveled (corresponding to the PEV charging duration needed). In this case study, the additional demand due to PEV charging at 4 PM can be estimated with these statistics.

Table 6-2 lists the percentage of vehicle trips for different purposes based on the 2009 NHTS data. Further analyses show that 37.04% of the errand trips in urban areas will be charging at home at 4 PM, and 20.21% of the commute trips will be charging at home 4 PM. Considering that 44.1% of all weekday urban area trips are errand trips, and 25.7% of all weekday urban area trips are office-to-home commute trips, a weighted average of 22% of urban area weekday trips has home charging occurring at 4 PM.

For non-urban areas (corresponding to rural areas in this study), 45.01% of the errand trips will be charging at home at 4 PM, and 25.45% of the commute trips will have home charging at 4 PM. Considering that 42.7% of all weekday non-urban area trips are errand trips, and 26.0% of all weekday non-urban area trips are office-to-home commute trips, a weighted average of 26% of non-urban area weekday trips has home charging occurring at 4 PM.

Table 6-2
Weekday Trip Distribution (from a previous study using 2009 NHTS data)

Area	Home to Home (Errand)	Home to Office	Office to Home	Office to Office
Urban	44.1%	25.9%	25.7%	4.2%
Non-Urban	42.7%	26.3%	26.0%	5.0%

75 http://cio.nist.gov/esd/emaildir/lists/t_and_d_interop/pdf00021.pdf

With these assumptions, we are able to estimate the load density for residential customers with PEVs, as listed in Table 6-3. For instance, if we assume that there are 2 customers per acre for a low density residential type, and at 100% penetration rate (that is, each customer has one PEV), then the contribution of PEV charging to the system peak, which is the load density value for PEV charging to be used for low density residential customers in the load forecast, is:

$$
\begin{aligned}
&= \frac{average\ charging\ demand\ (kW)}{unit} \times \frac{unit}{acre} \times \%\ of\ vehicle\ charging\ at\ home\ at\ 4PM \\
&= 2.55 \times 2 \times 22\% \\
&= 1.122 \frac{kW}{Acre}
\end{aligned}
$$

Different from residential customer PEV charging, commercial charging mainly arises due to travels to these locations for work/shopping/visit. The charging demand at commercial/industrial/institutional locations is not tied with customer count; instead, the charging demand is to a certain extent restricted by the charging facilities. In this demonstration, it is assumed that charging facilities are readily available corresponding to the PEV penetration rate. In other words, the available charging facility is proportional to the PEV penetration rate of interest.

It is assumed in the case study that 10% of the commercial/industrial/institutional land use is for parking. The number of parking lots available can be estimated from the average size of a parking space (that is, 120 square feet is assumed in this study, and there are 300 parking lots in one acre of land[76]). For example, if there are 300 parking spaces available at one location, and the PEV penetration rate under study is 10%, then it is assumed that there are 30 PEVs plugged in and demanding energy from the grid. From a similar calculation from 2009 NHTS data, 36% of PEVs plugged in will be charging at commercial locations at 4 PM.

Table 6-3
Land use assumptions for PEV loads

Type	Load Density (kW/acre)	Assumptions
Industrial / Business	54	10% of the land use is for parking
Extractive	0	-
Commercial (Retail & Services)	54	10% of the land use is for parking
Institutional / Government	54	10% of the land use is for parking
Rural Residential	0.3315	0.5 unit / acre
Low Density Residential	1.122	2 units / acre
Medium Density Residential	2.805	5 units / acre
High Density Residential	11.22	20 units / acre

[76] http://en.wikipedia.org/wiki/Parking_space

Table 6-3 (continued)
Land use assumptions for PEV loads

Type	Load Density (kW/acre)	Assumptions
Communication / Utilities	0	-
Transportation	0	-
Agriculture / Vacant	0	-
Parks / Outdoor Recreation	0	-
Natural / Woodland / Water / Other	0	-

For instance, if at an institutional customer location 10% of the land use is for parking, then at 100% penetration rate the contribution of PEV charging to the system peak, which is the load density value for PEV charging in the load forecast, is:

$$= \frac{average\ charging\ demand\ (kW)}{unit} \times \frac{\#\ of\ parking\ space}{acre} \times 10\%\ (utilized\ for\ parking\ by\ assumption) \times \%\ of\ vehicle\ charging\ at\ 4PM$$
$$= 5 \times 300 \times 10\% \times 36\%$$
$$= 54 \frac{kW}{Acre}$$

The PEV charging load density for various land-use types are summarized in Table 6-3. The case study presents two scenarios: a higher PEV penetration scenario (referred to as EV1) in which the PEV penetration rate reaches 30% in 20 years from the base year; a lower PEV penetration scenario (referred to as EV2) in which the PEV penetration rate reaches 10% in 20 years from the base year.

Assumptions for DG

For the specific case of DG there are numerous technology alternatives, including PV, wind, biomass, etc. Given the remarkable interest and proliferation that PV-DG is currently experiencing; this demonstration focuses on that technology exclusively. However, other technologies or mix of technologies could also be analyzed provided that the average size of DG units and output profiles are available. This demonstration utilizes the following average sizes for PV-DG units which were obtained from an actual PV-DG study project data:

- 5.2 kW for residential customers
- 56.6 kW for commercial customers
- 168.9 kW for industrial customers

PV output also varies along the day. A sample PV output profile is shown in Figure 6-2. PV output typically reaches its maximum value at noon. As discussed in section 0, conventional (no smart technology) system peaks are assumed to occur at 4 PM. The output of PV-DG units at this time is typically 56% of that at noon, that is, the load offset effect at 4 PM of a PV-DG plant would only be 56% of its maximum output. This factor is considered in the load density calculations.

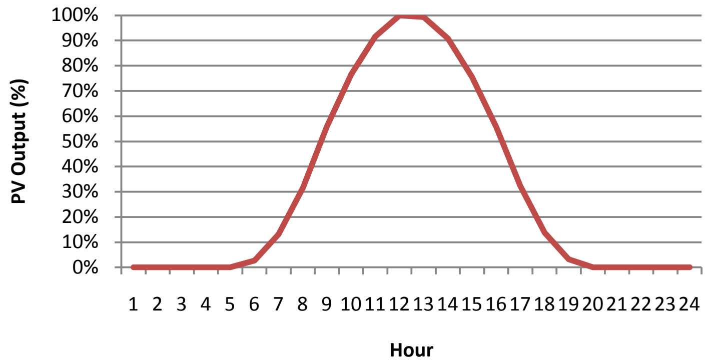

Figure 6-2
Sample PV Output Profile

The PV-DG load density for different customer types is calculated straightforwardly. Since PV-DG output offsets the system load, the load density values are negative.

$$(-1) \times \frac{rated\ PV\ output\ (kW)}{unit} \times 56\%\ (4PM\ output\ ratio) \times \frac{unit}{acre}$$

For example, if it is assumed that there are 5 customers per acre for a medium density residential customer type, at 100% penetration rate (that is, all customers have PV-DG installed on their premises), the contribution of PV-DG to the system peak, which is the load density value for PV-DG in the load forecast, is:

$$= -5.2\frac{kW}{unit} \times 56\% \times 5\frac{unit}{acre}$$
$$= -14.56\frac{kW}{Acre}$$

One exception is high density residential customer. For example, a customer living in an apartment complex may not be able to easily install a PV plant. Instead, it is more likely for the property management companies to install solar panels for the entire community at various paces. Therefore, in this case study, high density residential customers are treated as commercial customers, and the load density is calculated based on the number of structures/buildings, instead of the customer count as in other residential land use types.

During the load forecast process, the PV-DG load densities for different customer types will be multiplied by their corresponding land uses and their penetration rates so that the contribution of PV-DG output can be estimated. The case study presents two scenarios: a higher PV penetration scenario (referred to as <u>PV1</u>) in which the PV penetration rate reaches 30% in 20 years from the base year; a lower PV penetration scenario (referred to as <u>PV2</u>) in which the PEV penetration rate reaches 15% in 20 years from the base year.

Table 6-4
Land use assumptions for PV-DG

Type	Load Density (kW/acre)	Assumptions
Industrial / Business	-18.9168	0.2 unit / acre
Extractive	0	-
Commercial (Retail & Services)	-31.64	1 unit / acre
Institutional / Government	-15.82	0.5 unit / acre
Rural Residential	-1.456	0.5 unit / acre
Low Density Residential	-5.824	2 units / acre
Medium Density Residential	-14.56	5 units / acre
High Density Residential	-5.824	2 structures / acre
Communication / Utilities	0	-
Transportation	0	-
Agriculture / Vacant	0	-
Parks / Outdoor Recreation	0	-
Natural / Woodland / Water / Other	0	-

Assumptions for Net Zero Energy Buildings

The Energy Independence and Security Act of 2007 (EISA 2007) set a goal of NZE for all new commercial buildings by 2030, 50% of all commercial buildings by 2040, and all commercial buildings by 2050.[77] According to case studies discussed in the specialized literature,[78] a building with NZE can achieve more than 50% energy reduction during peak power by using renewable energy and chilled water thermal storage.

In this demonstration, it is assumed that NZE buildings will reduce their peak loads by 60%. This peak load reduction applies to Industrial/Commercial/Institutional land uses. The case study presents two scenarios: a high penetration scenario (referred to as NZE1) in which the NZE penetration rate increases 1% per year in the 20 years of the forecast range; and a medium penetration scenario (referred to as NZE2) in which the NZE penetration rate increases 0.5% per year in the 20 years of the forecast range. These two penetration scenarios of NZE are summarized in Table 6-5 and Table 6-6.

[77] http://www1.eere.energy.gov/femp/regulations/eisa.html
[78] J. Elliot, K. Brown, Not Too Fast, Not Too Slow: A Sustainable University Campus Community Sets an Achievable Trajectory toward Zero Net Energy, Proc. of 2010 ACEEE Summer Study on Energy Efficiency in Buildings, Aug. 2010

The penetration level is defined on the basis of peak load. For example, 10% of NZE penetration indicates that 10% of the base load is NZE. If peak load for the base scenario for a specific year is 100 kW and the penetration level is 10%, then 10 kW of the load is NZE. As it is assumed that NZE buildings will reduce their peak loads by 60%, the demand reduction from NZE will be 60% of 10 kW or a reduction of 6kW, and the forecasted load of this NZE scenario will be 94 kW.

Table 6-5
Net Zero Energy Building 1 (High Penetration)

Year	Base	1	2	3	4	5	6	7	8	9	10
Net Zero Energy (%)	0.0	1.0	2.0	3.0	4.0	5.0	6.0	7.0	8.0	9.0	10.0
Year		**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
Net Zero Energy (%)		11.0	12.0	13.0	14.0	15.0	16.0	17.0	18.0	19.0	20.0

Table 6-6
Net Zero Energy Building 2 (Medium Penetration)

Year	Base	1	2	3	4	5	6	7	8	9	10
Net Zero Energy (%)	0.0	0.5	1.0	1.5	2.0	2.5	3.0	3.5	4.0	4.5	5.0
Year		**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
Net Zero Energy (%)		5.5	6.0	6.5	7.0	7.5	8.0	8.5	9.0	9.5	10.0

Assumptions for Demand Response

Demand Response infrastructure allows utilities to communicate with and control Programmable and Communicating Devices (PCD) inside their premises, such as smart thermostats and load cycling switches of air conditioning and water heaters. Demand Response is not new, for instance various forms of load management, including direct load control, have been used for years for large commercial loads. One of the key differences between traditional and modern/future Demand Response is the availability of AMI, which allows monitoring the results of Demand Response commands in quasi-real time, and using this information to make further adjustments aimed at increasing effectiveness.

An important consideration when implementing Demand Response is the geographic location of the distribution system under study. For instance, distribution systems in the Southern US are largely summer peaking due to heavy electricity utilization by air conditioning loads, hence a Demand Response program in this region may achieve higher energy reduction than in the Northeastern US, where there are less air conditioning demand. Moreover, it is worth noting that base forecasting for most utilities already accounts for existing Demand Response programs. Thus, forecasting the effect of Demand Response should consider only future programs, otherwise there would be a “double counting” effect.

According to the specialized literature, Demand Response could reduce peak load by 10% to 20%.[79] In this demonstration, it is assumed that Demand Response will reduce 10% of peak load. This will apply to Industrial/Commercial/Institutional and all residential land uses. The case study presents two scenarios: a high penetration scenario (referred to as DR1) in which the DR penetration rate increases 10% per year until reaching 80% in the 8th year of the forecast range; a medium penetration scenario (referred to as DR2) in which the DR penetration rate increases 5% per year until reaching 70% in the 14th year of the forecast range. These penetration scenarios are summarized in Table 6-7 and Table 6-8.

Table 6-7
Demand Response 1 (High Penetration)

Year	Base	1	2	3	4	5	6	7	8	9	10
Demand Response (%)	0.0	10.0	20.0	30.0	40.0	50.0	60.0	70.0	80.0	80.0	80.0
Year		**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
Demand Response (%)		80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0

Table 6-8
Demand Response 2 (Medium Penetration)

Year	Base	1	2	3	4	5	6	7	8	9	10
Demand Response (%)	0.0	5.0	10.0	15.0	20.0	25.0	30.0	35.0	40.0	45.0	50.0
Year		**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
Demand Response (%)		55.0	60.0	65.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0

Assumptions for Energy Efficiency

In 2011, the federal government proposed the *Better Buildings* initiative to make all commercial buildings 20% more energy efficient before 2020.[80] In this demonstration, it is assumed that an energy efficiency scenario will reduce 15% of peak load, which applies to Industrial/ Commercial/Institutional and all residential land uses. This estimate was estimated based on analysis of utility data and the specialized literature. For instance, results for a utility in the Southern US showed that air conditioning accounts for 65% to 75% of total load at peak, since replacing 10-year old air conditioning units by modern devices could reduce energy consumption by 20%;[81] the implementation of a system wide energy efficiency program could arguably lead to a 15% energy reduction.[82]

In addition to air conditioning, other technologies such as compact fluorescent lamp, liquid crystal display (LED) bulb, spray foam insulation, or hi-tech aerogel insulation decrease total energy consumption as well. Furthermore, according to "Building America's Best Practices

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[79] P.A. Boyd, G.B. Parker, and D.D. Hatley, Load Reduction, Demand Response and Energy Efficient Technologies and Strategies, Prepared for the U.S. Department of Energy under Contract DE-AC05-76RL01830, Nov 2008
[80] http://www1.eere.energy.gov/buildings/betterbuildings/
[81] http://energy.gov/energysaver/articles/central-air-conditioning
[82] This is a rough assumption used for demonstration purposes only, a utility planner would need to conduct a more detailed analysis to obtain a more accurate estimation

Guidelines" can reduce total energy consumption by 30-40% for typical home or commercial building.[83] The combined implementation of these technologies could help improve system wide energy efficiency. However, it is worth noting that energy efficiency appliances may not reduce energy consumption as much as forecasted by straightforward statistical models because of the "rebound effect".[84] Decreasing energy demand by using energy efficient appliances can create lower electrical bills which could persuade consumers to use more energy. For example, 20% improvement for air conditioning may lead to 20% decrease in energy consumption only for air conditioning but consumers may use more energy for other purposes such as a bigger TV or new appliances.

The energy efficiency case study presents two scenarios: a high penetration scenario (referred to as EE1) in which the energy efficiency penetration rate increases 5% per year during the 20 years forecast range; a medium penetration scenario (referred to as EE2) in which the energy efficiency penetration rate increases 5% per year for the first 10 years and then 2.5% percent per year for the next 10 years in the forecast range. Penetration levels for this demonstration have been defined in a similar fashion as the NZE case, on the basis of peak load, and are summarized in Table 6-9 and Table 6-10.

Table 6-9
Energy Efficiency 1 (High Penetration)

Year	Base	1	2	3	4	5	6	7	8	9	10
Energy Efficiency (%)	0.0	5.0	10.0	15.0	20.0	25.0	30.0	35.0	40.0	45.0	50.0
Year		**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
Energy Efficiency (%)		55.0	60.0	65.0	70.0	75.0	80.0	85.0	90.0	95.0	100.0

Table 6-10
Energy Efficiency 2 (Medium Penetration)

Year	Base	1	2	3	4	5	6	7	8	9	10
Energy Efficiency (%)	0.0	5.0	10.0	15.0	20.0	25.0	30.0	35.0	40.0	45.0	50.0
Year		**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
Energy Efficiency (%)		52.5	55.0	57.5	60.0	62.5	65.0	67.5	70.0	72.5	75.0

Assumptions for Reactive Power

The large majority of load forecasts focus on estimating real power growth; this is mainly based on the fact that utility power factors are generally kept relatively close to unity via local reactive power compensation. Hence, it is assumed that real power forecasts provide a good estimation for apparent power requirements which are ultimately used for capacity planning and equipment

[83] Building Technologies Program, Energy Efficiency & Renewable Technology, U.S. Department of Energy
[84] The Rebound Effect: as assessment of the evidence for economy-wide energy savings from improved energy efficiency, UK Energy Research Centre, 2007

selection. However, this assumption can be challenged for scenarios such as DG proliferation.[85] In general, if the assumption of unity power factors does not hold true for a specific area or utility service territory, combined real and reactive power forecasting provides a more accurate depiction of load growth for capacity planning and system efficiency improvement. Evidently, this requires additional effort for gathering historical reactive power load data and reactive power load densities for different land use types. Interestingly, low utility power factors are not uncommon, analyses conducted by the authors for a North American utility showed an overall utility power factor equal to 0.92 lagging. Hence, in order to obtain a reactive (MVAr) and apparent power (MVA) load forecast this demonstration assumed that the power factor for the base year (PF = 0.92 lagging) would also apply to future years. Moreover, for those cases involving DG it was assumed that renewable generation would operate at unity power factor.

Summary

The following list summarizes the different simulation scenarios defined in section 0, including main assumptions and simplifications:

- The case study presents two PEV simulation scenarios: a higher PEV penetration scenario (referred to as EV1) in which the PEV penetration rate reaches 30% in 20 years from the base year; a lower PEV penetration scenario (referred to as EV2) in which the PEV penetration rate reaches 10% in 20 years from the base year.
- The case study presents two PV-DG simulation scenarios: a higher PV penetration scenario (referred to as PV1) in which the PV penetration rate reaches 30% in 20 years from the base year; a lower PV penetration scenario (referred to as PV2) in which the PEV penetration rate reaches 15% in 20 years from the base year.
- The case study presents two Net Zero Energy simulation scenarios: a high penetration scenario (referred to as NZE1) in which the NZE penetration rate increases 1% per year in the 20 years of the forecast range; a medium penetration scenario (referred to as NZE2) in which the NZE penetration rate increases 0.5% per year in the 20 years of the forecast range.
- The case study presents two Demand Response simulation scenarios: a high penetration scenario (referred to as DR1) in which the DR penetration rate increases 10% per year until reaching 80% in the 8th year of the forecast range; a medium penetration scenario (referred to as DR2) in which the DR penetration rate increases 5% per year until reaching 70% in the 14th year of the forecast range.
- The case study presents two Energy Efficiency scenarios: a high penetration scenario (referred to as EE1) in which the energy efficiency penetration rate increases 5% per year during the 20 years forecast range; a medium penetration scenario (referred to as EE2) in which the energy efficiency penetration rate increases 5% per year for the first 10 years and then 2.5% percent per year for the next 10 years in the forecast range.
- Forecasted loads include real, reactive and apparent power for an assumed base load system wide power factor of 0.92 lagging and DG and NZE operation at unity power factor.

[85] Since DG is generally operated at unity power factor, DG proliferation causes a decrease in the real power delivered by distribution substations while keeping reactive power relatively constant, the overall effect is lower power factors than those observed under no DG scenarios

Demonstration Results

The results of the simulation scenarios for the cases previously discussed are shown in Table 6-11 to Table 6-13, they include system MW, MVAr, and MVA peak loads for a period of 20 yrs. Figure 6-3 to Figure 6-5 display results as charts. The particular data used in the analyses showed that this service area was expected to experience significant load growth during the first year of the simulation, and then from low to moderate to aggressive growth for the following scenarios.

Figure 6-6 to Figure 6-21 display contour plot maps for base year and horizon year of all scenarios. Here it is important to remember that the base case considers conventional load growth, that is, no particular or significant penetration of smart grid technologies, while the smart technology scenarios consider proliferation of new technologies as discussed in the previous section. Moreover, combinations of a few selected scenarios have also been simulated. As explained in the previous section this particular load forecasting algorithm takes the overall annual peak system forecast (that shown in Figure 6-3 to Figure 6-5) and distribute in a coordinated fashion among all small areas for each of the 20 years under study. This is done in such a way that the sum of the total load growth and peak demands of all small areas matches the system load growth and peak demand.

These plots show the key contribution of a spatial load forecast; it allows analyzing and estimating the spatial distribution of load growth and peak loads for numerous what-if scenarios. The main advantage of these plots is that they show distribution planners the spatial distribution of load growth for the service area, that is, where and when load growth is expected to occur and the expected magnitude of peak loads. The outputs of these simulations can be exported into distribution system analysis software such as CYMDIST, SynerGEE, Windmil, etc to investigate in more detail how these expected load growth and peak loads would affect existing facilities. Moreover, these results can be used to identify where new distribution facilities would be required and how they should be specified and designed (for example, substation capacity, feeder length, etc). In order to illustrate this concept Figure 6-22 and Figure 6-23 show the individual *base case* forecasting for eight selected small areas, and Figure 6-24 to Figure 6-27 show the individual *scenario* (DG, NZE, etc) forecasting for small areas A, B, C, and D. Finally, Figure 6-28 shows the five-year step spatial load forecast for the service area for both, base case and EV case. If required, similar plots could be generated on a yearly basis; this would provide a detailed depiction of load growth.

It is worth noting that the results of these scenarios are estimations of prospective forecasted peak loads under available data and previously stated assumptions for illustrative purposed. In a real utility setting the next step would be to review, challenge, and re-evaluate the results if necessary, particularly when and if new data and more accurate assumptions become available.

Table 6-11
Load forecasting results (MW)

Scenario	Annual Peak (MW)										
	0	1	2	3	4	5	6	7	8	9	10
Base	679	743	764	786	808	830	850	867	883	895	906
EV1	679	745	768	793	817	841	869	894	916	935	952
PV1	679	739	756	773	792	809	814	820	824	826	827
PV1 and EV1	679	741	760	780	800	820	833	847	857	866	873
PV2	679	741	760	780	800	819	834	847	859	868	875
EV2	679	745	768	793	817	841	866	888	907	923	937
PV2 & EV2	679	743	764	786	809	830	850	868	883	896	906
PV2 & EV1	679	743	764	786	809	830	853	874	892	908	921
PV1 & EV2	679	741	760	780	800	820	831	841	849	854	858
NZE1	679	740	758	776	795	812	828	842	853	861	868
NZE2	679	742	761	781	801	821	839	855	868	878	887
EE1	679	738	753	768	784	799	812	822	830	835	838
EE2	679	738	753	768	784	799	812	822	830	835	838
DR1	679	736	749	763	776	788	799	807	813	824	834
DR2	679	739	756	774	792	809	824	837	848	855	861

Scenario	Annual Peak (MW)									
	11	12	13	14	15	16	17	18	19	20
Base	914	921	926	930	933	935	937	938	939	940
EV1	966	977	986	993	999	1,003	1,007	1,009	1,011	1,013
PV1	826	826	825	824	823	822	821	821	820	820
PV1 and EV1	878	882	885	887	889	890	891	892	892	893
PV2	881	885	888	891	893	894	895	896	897	897
EV2	947	956	963	968	972	975	978	979	981	982
PV2 & EV2	914	920	925	929	932	934	936	937	938	939
PV2 & EV1	933	942	949	955	959	963	965	967	969	970
PV1 & EV2	860	861	862	862	862	862	862	862	862	862
NZE1	872	874	875	875	874	872	870	868	865	861
NZE2	893	897	900	902	903	904	903	903	902	901
EE1	839	838	836	833	829	824	818	813	806	800
EE2	843	845	847	847	846	845	843	840	838	835
DR1	842	848	852	856	859	861	862	864	865	865
DR2	864	866	866	865	868	870	872	873	874	875

Table 6-12
Load forecasting results (MVAr)

Scenario	Annual Peak (MVAr)										
	0	1	2	3	4	5	6	7	8	9	10
Base	289	317	325	335	344	353	362	370	376	381	386
EV1	289	317	327	338	348	358	370	381	390	399	406
PV1	289	317	325	335	344	353	362	370	376	381	386
PV1 & EV1	289	317	327	338	348	358	370	381	390	399	406
PV2	289	317	325	335	344	353	362	370	376	381	386
EV2	289	317	327	338	348	358	369	378	386	393	399
PV2& EV2	289	317	327	338	348	358	369	378	386	393	399
PV2& EV1	289	317	327	338	348	358	370	381	390	399	406
PV1 & EV2	289	317	327	338	348	358	369	378	386	393	399
NZE1	289	315	323	331	338	346	353	359	363	367	370
NZE2	289	316	324	333	341	350	357	364	370	374	378
EE1	289	314	321	327	334	340	346	350	354	356	357
EE2	289	314	321	327	334	340	346	350	354	356	357
DR1	289	313	319	325	331	336	340	344	346	351	355
DR2	289	315	322	330	337	345	351	357	361	364	367

Scenario	Annual Peak (MVAr)									
	11	12	13	14	15	16	17	18	19	20
Base	389	392	394	396	397	398	399	400	400	400
EV1	411	416	420	423	426	427	429	430	431	432
PV1	389	392	394	396	397	398	399	400	400	400
PV1 & EV1	411	416	420	423	426	427	429	430	431	432
PV2	389	392	394	396	397	398	399	400	400	400
EV2	404	407	410	412	414	415	416	417	418	418
PV2& EV2	404	407	410	412	414	415	416	417	418	418
PV2& EV1	411	416	420	423	426	427	429	430	431	432
PV1 & EV2	404	407	410	412	414	415	416	417	418	418
NZE1	371	372	373	373	372	372	371	370	368	367
NZE2	380	382	384	384	385	385	385	385	384	384
EE1	358	357	356	355	353	351	349	346	344	341
EE2	359	360	361	361	360	360	359	358	357	356
DR1	358	361	363	365	366	367	367	368	368	369
DR2	368	369	369	369	370	371	371	372	372	373

Table 6-13
Load forecasting results (MVA)

Scenario	Annual Peak (MVA)										
	0	1	2	3	4	5	6	7	8	9	10
Base	738	808	831	854	878	902	924	943	959	973	985
EV1	738	810	835	862	888	914	945	971	996	1,017	1,035
PV1	738	804	823	843	863	883	891	900	906	910	912
PV1 & EV1	738	806	828	850	873	895	912	928	942	953	963
PV2	738	806	827	848	871	892	909	924	937	948	956
EV2	738	810	835	862	888	914	942	965	986	1,004	1,018
PV2& EV2	738	808	831	856	880	904	927	947	964	978	990
PV2& EV1	738	808	831	856	880	904	930	953	974	991	1,007
PV1 & EV2	738	806	828	850	873	895	909	922	932	940	946
NZE1	738	804	824	844	864	883	900	915	927	936	943
NZE2	738	806	827	849	871	892	912	929	943	955	964
EE1	738	802	818	835	852	868	882	894	902	908	911
EE2	738	802	818	835	852	868	882	894	902	908	911
DR1	738	800	814	829	844	857	868	877	883	896	906
DR2	738	804	822	842	861	879	896	910	921	930	936

Scenario	Annual Peak (MVA)									
	11	12	13	14	15	16	17	18	19	20
Base	994	1,001	1,006	1,011	1,014	1,016	1,018	1,020	1,021	1,022
EV1	1,050	1,062	1,072	1,080	1,086	1,091	1,094	1,097	1,099	1,101
PV1	914	914	914	914	914	913	913	913	913	912
PV1 & EV1	970	975	980	983	986	988	989	990	991	992
PV2	963	968	972	975	977	979	980	981	982	983
EV2	1,030	1,039	1,046	1,052	1,057	1,060	1,063	1,065	1,066	1,067
PV2& EV2	999	1,007	1,012	1,017	1,020	1,023	1,025	1,026	1,027	1,028
PV2& EV1	1,019	1,030	1,038	1,044	1,049	1,053	1,056	1,059	1,061	1,062
PV1 & EV2	950	952	954	956	956	957	957	958	958	958
NZE1	948	950	951	951	950	948	946	943	940	936
NZE2	971	975	979	981	982	982	982	981	980	979
EE1	912	911	909	905	901	895	890	883	877	870
EE2	916	919	920	920	920	918	916	914	911	908
DR1	915	921	926	930	933	936	937	939	940	941
DR2	939	941	941	940	943	946	948	949	950	951

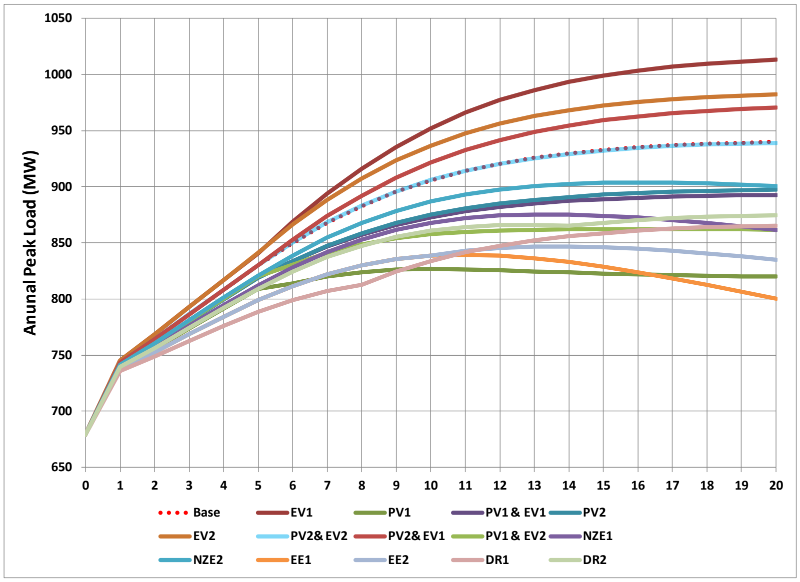

Figure 6-3
Forecasted annual peak load (MW) for scenarios under analysis

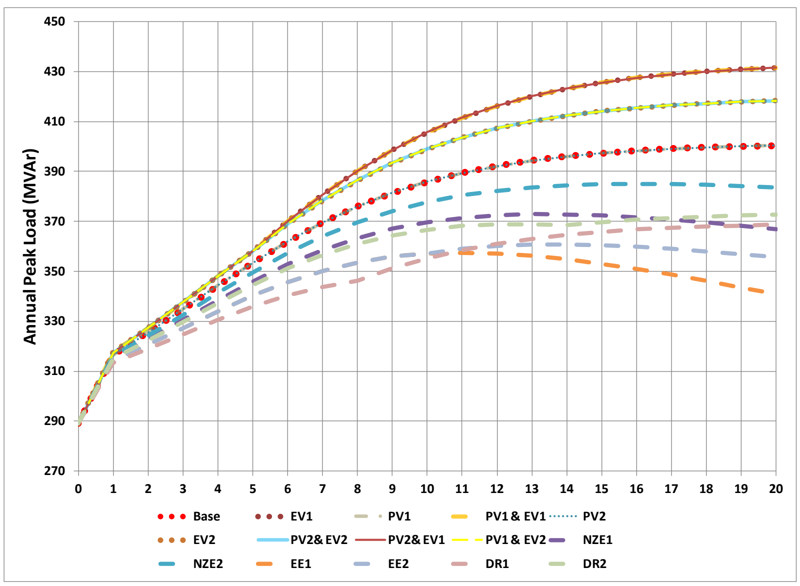

Figure 6-4
Forecasted annual peak load (MVAr) for scenarios under analysis

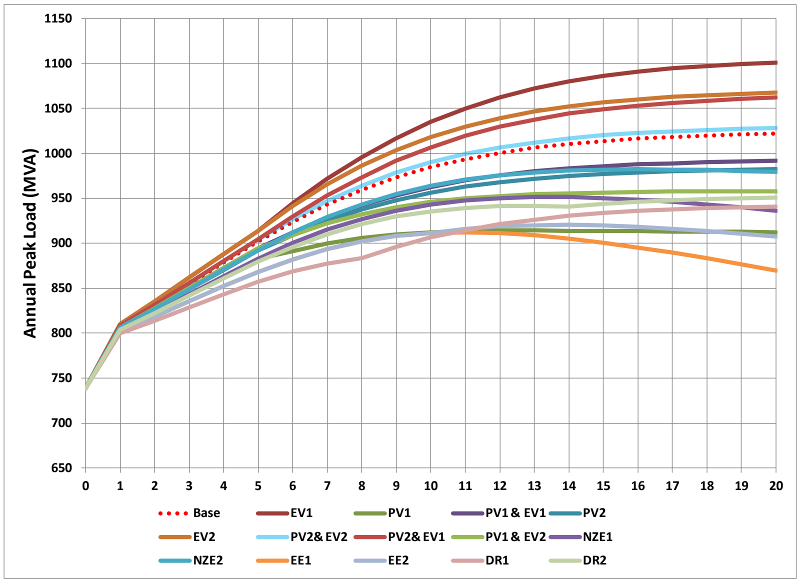

Figure 6-5
Forecasted annual peak load (MVA) for scenarios under analysis

kW	Color code
0	
1	
2	
3	
4	
5	
6	
7	
8	
9	
10	
12	
14	
16	
18	
20	
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2200	
2300	
>=2400	

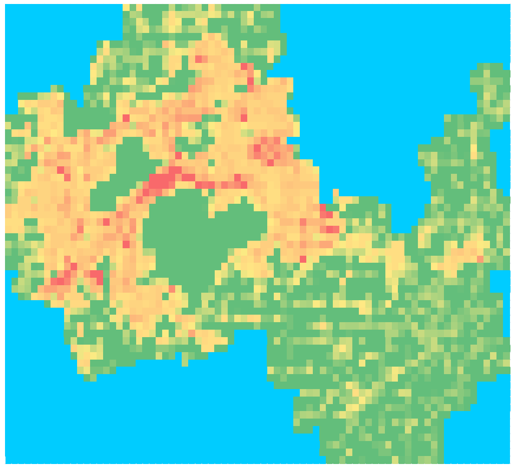

Figure 6-6
Base scenario (year 0)

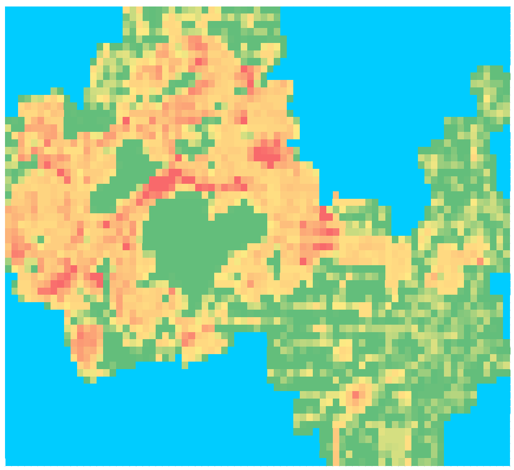

Figure 6-7
Base scenario (year 20)

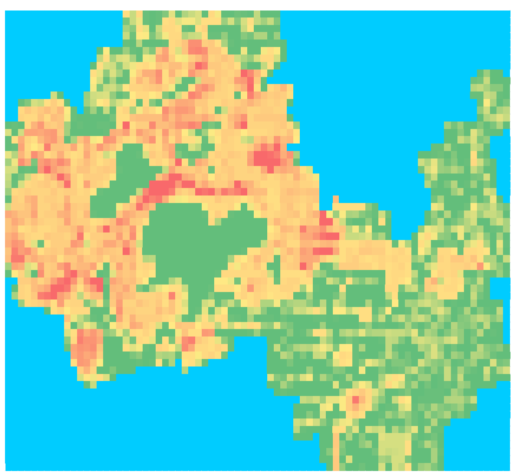

Figure 6-8
EV1 scenario (year 20)

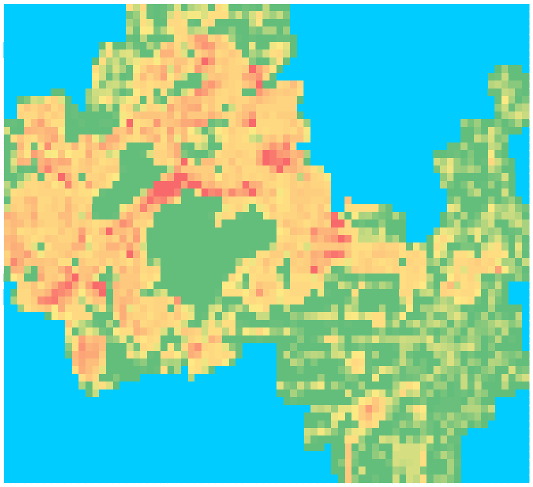

Figure 6-9
PV1 scenario (year 20)

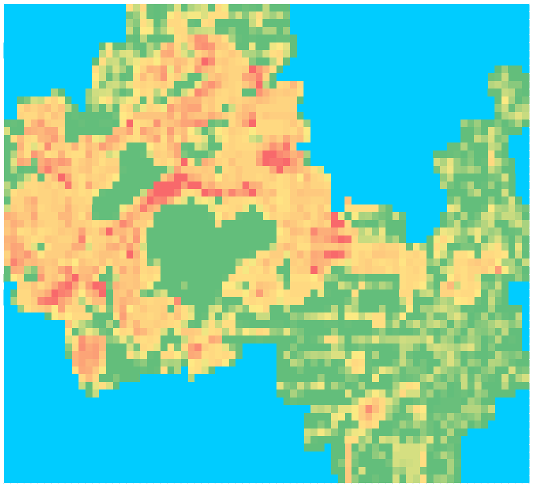

Figure 6-10
PV1 & EV1 scenario (year 20)

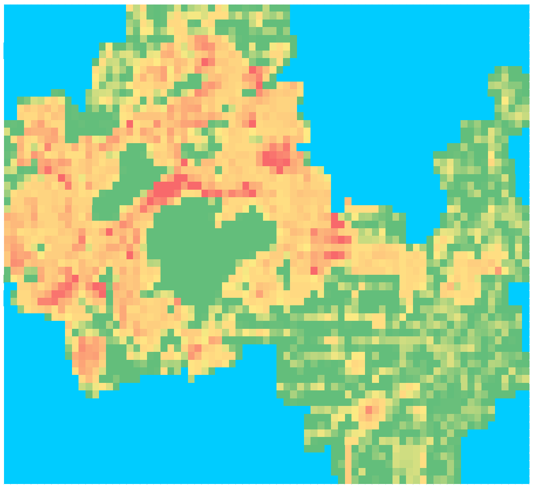

Figure 6-11
PV2 (year 20)

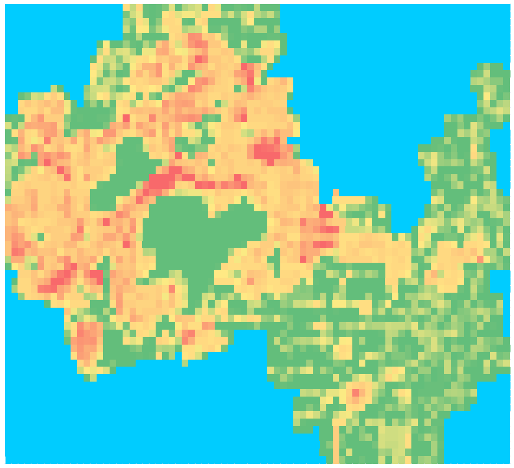

Figure 6-12
EV2 (year 20)

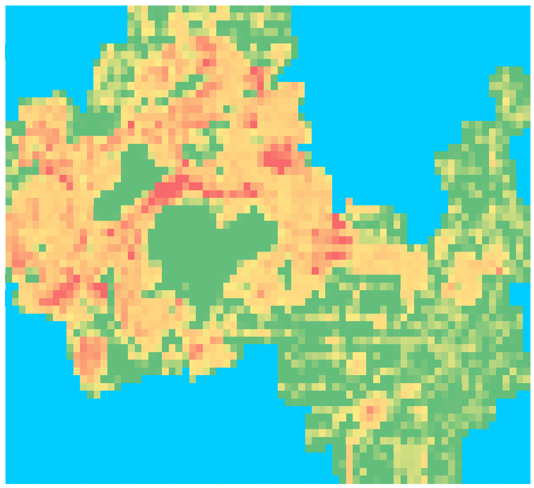

Figure 6-13
PV2 & EV2 (year 20)

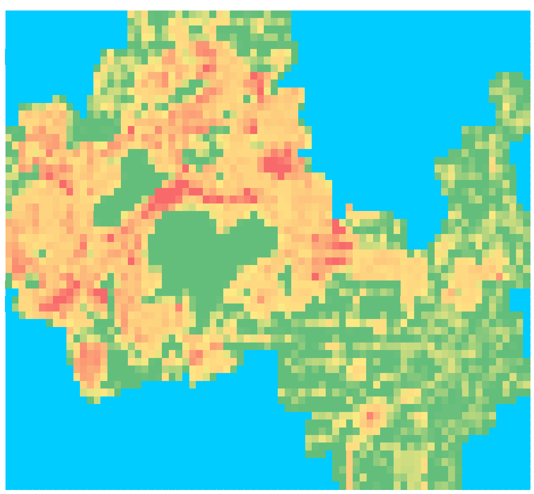

Figure 6-14
PV2 & EV (year 20)

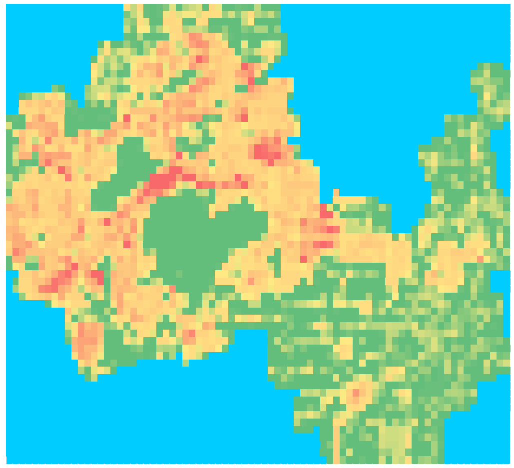

Figure 6-15
PV & EV2 (year 20)

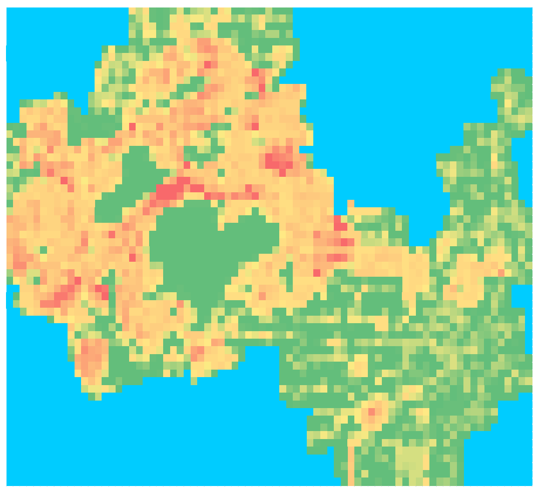

Figure 6-16
NZE1 (year 20)

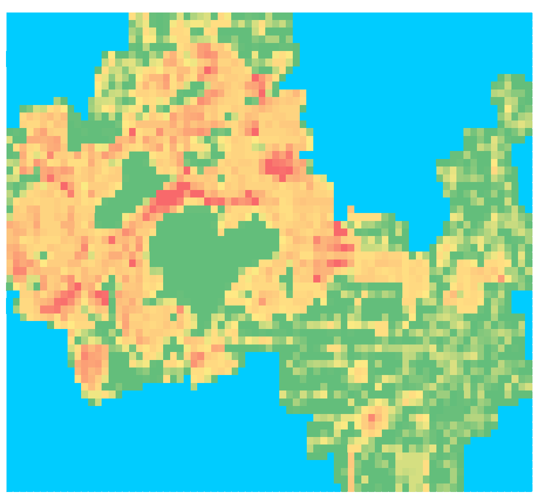

Figure 6-17
NZE2 (year 20)

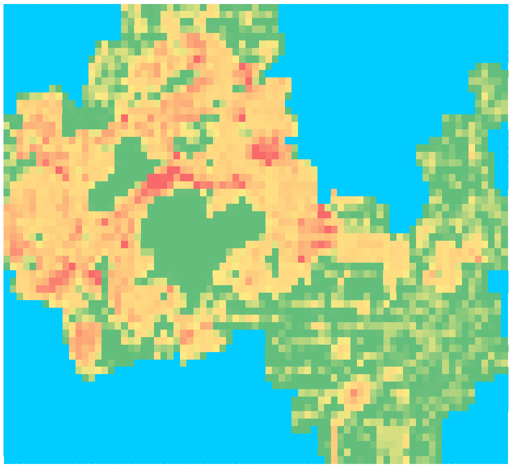

Figure 6-18
EE1 (year 20)

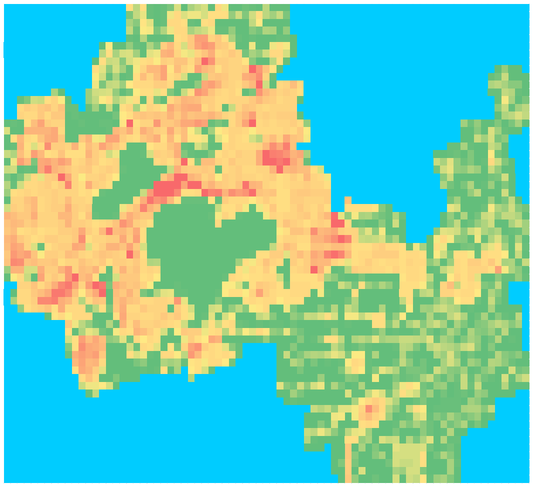

Figure 6-19
EE2 (year 20)

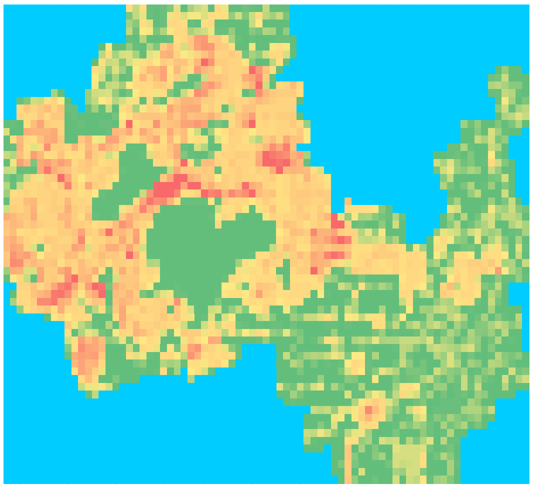

Figure 6-20
DR1 (year 20)

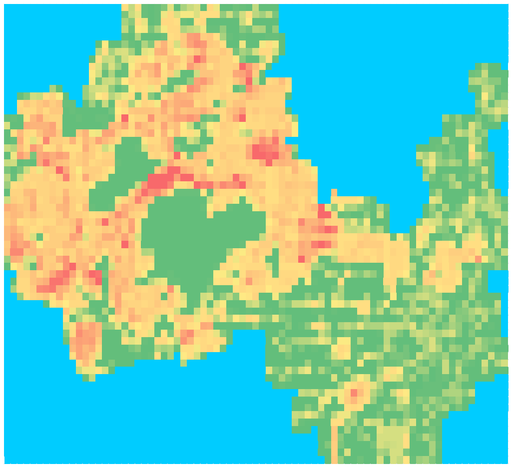

Figure 6-21
DR2 (year 20)

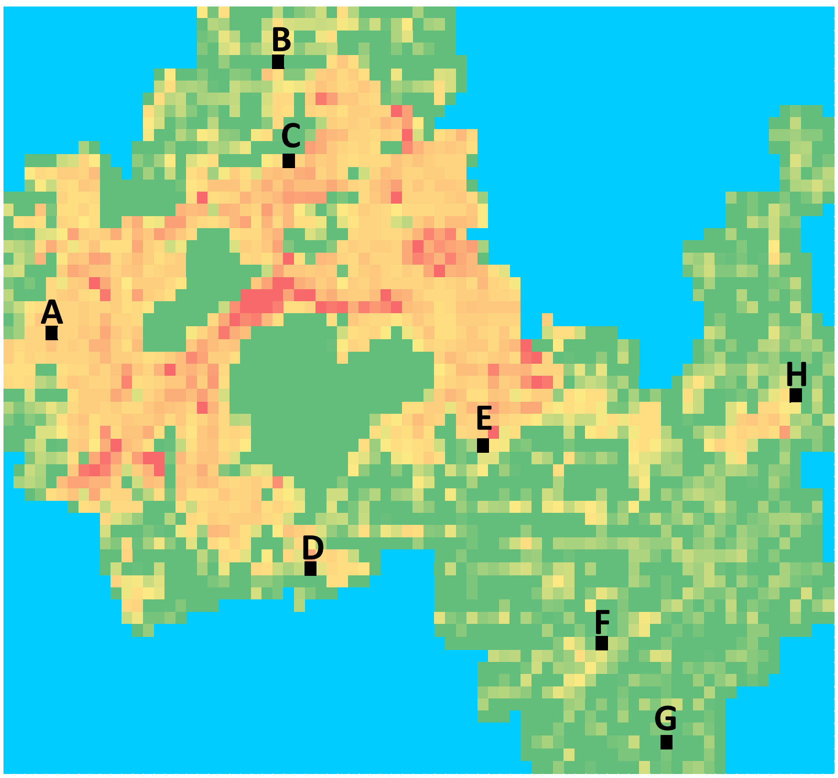

Figure 6-22
Example of 8 Small Areas

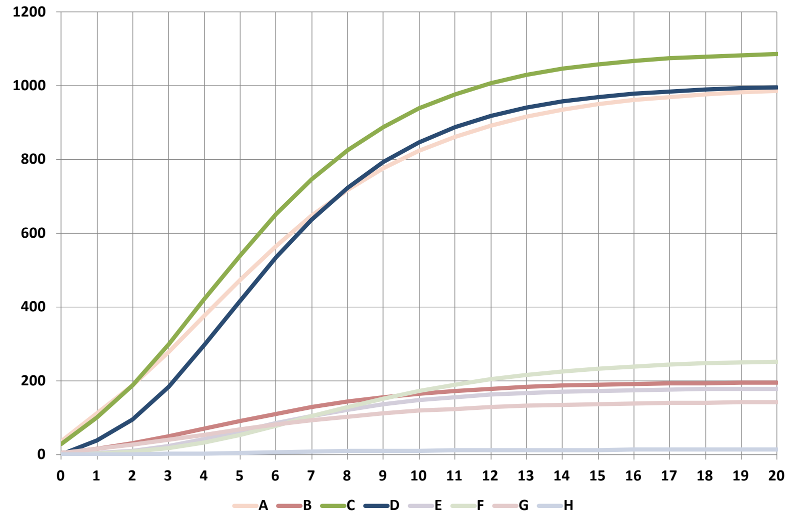

Figure 6-23
S Base case S-curve forecasting for 8 small areas (kW)

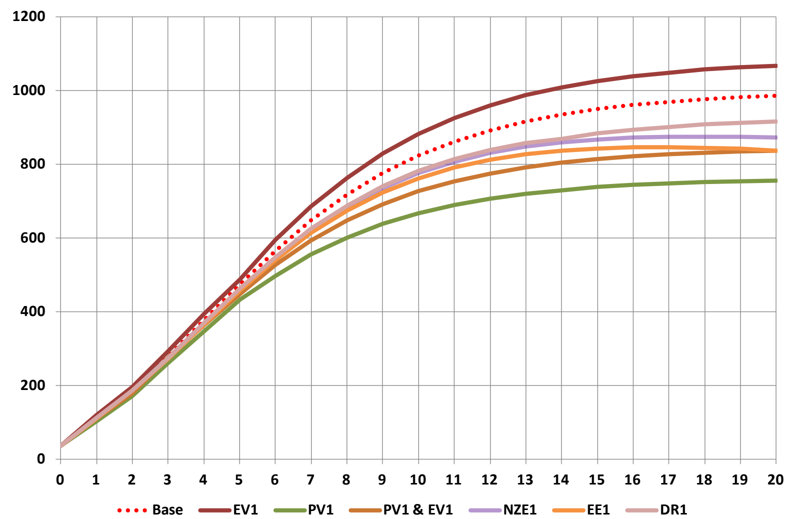

Figure 6-24
S-curve forecasting for small area A (kW)

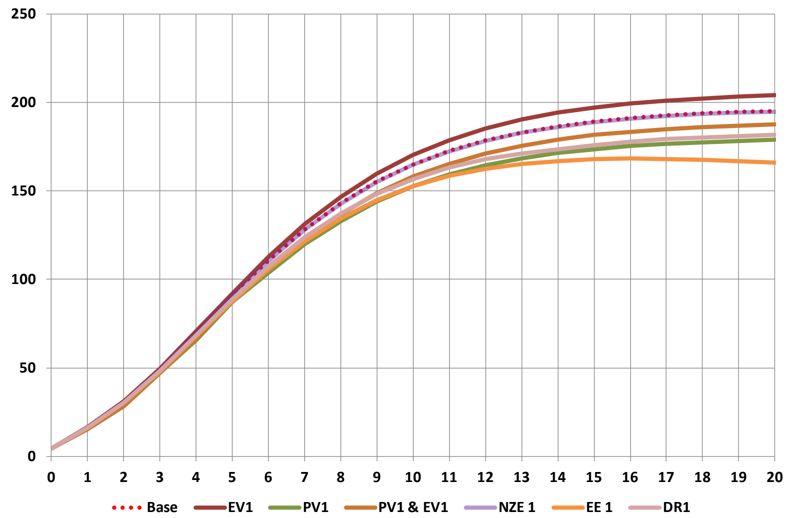

Figure 6-25
S-curve forecasting for small area B (kW)

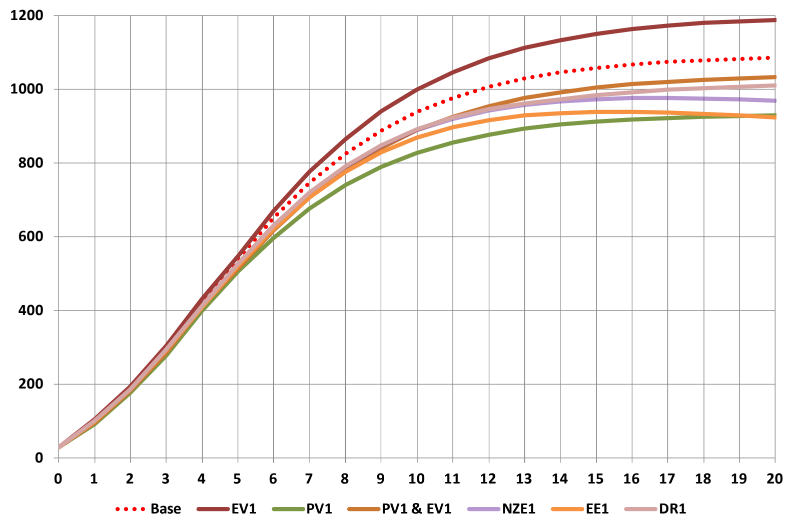

Figure 6-26
S-curve forecasting for small area C (kW)

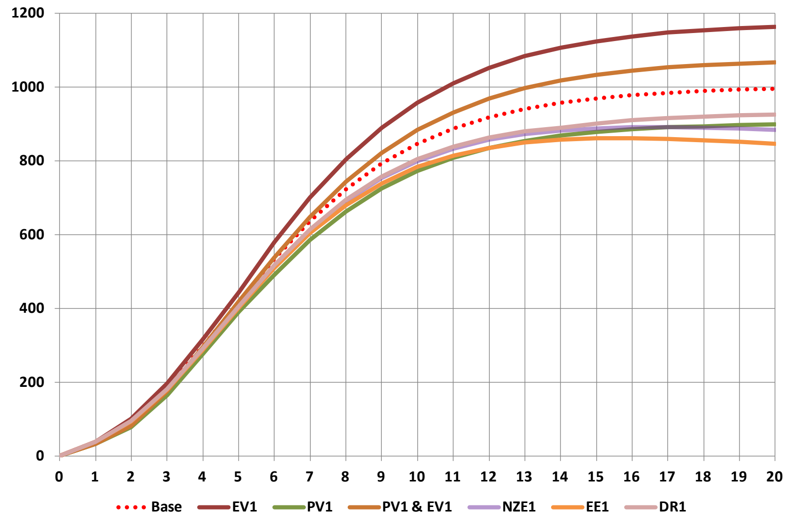

Figure 6-27
S-curve forecasting for small area D (kW)

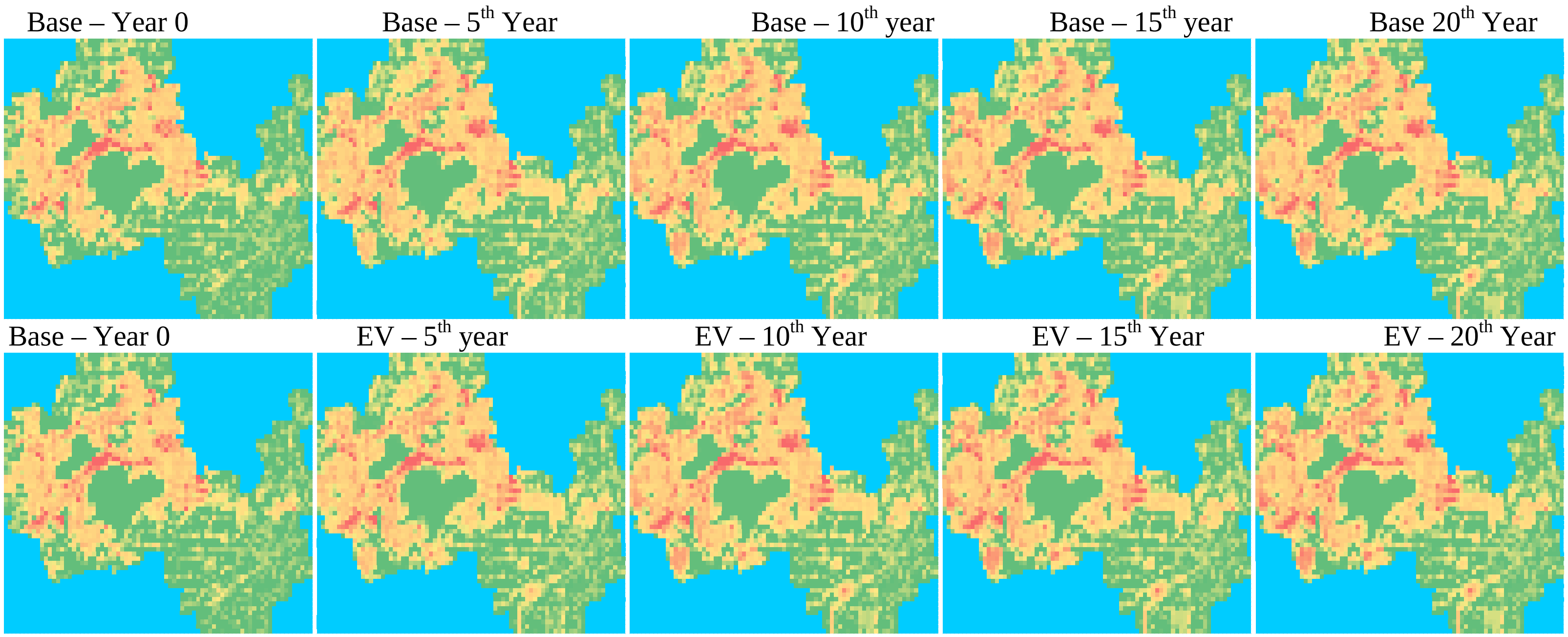

Figure 6-28
Multiple year service area spatial load forecast for base and EV scenario

7 CONCLUSIONS

Distribution load forecasting is the first step in distribution planning. Its objective is to determine the location and timing of electric load growth in every small geographic area of the utility service territory, with those areas being sufficiently small and specific to provide system planners with sufficient detail as to the location and density of local demands so that they can successfully match system capacity to load. This document discusses load forecasting in the context of conventional and smart distribution systems, with emphasis on *spatial load forecasting*, which plays a critical role in the planning of modern/future distribution systems.

In the particular case of conventional distribution systems there are numerous and well-known load forecasting methodologies and software tools. Challenges generally reside in the load forecasting and distribution planning processes themselves (rather than in the specific methodologies or software tools), and in the availability of a supporting utility enterprise system infrastructure that ensures gathering and recording the accurate data required for efficient load forecasting.

The successful planning of smart distribution systems requires either specialized load forecasting methodologies or a combination of upfront data processing and analysis and utilization of existing methodologies and software tools. The challenge in this case is not the availability of data gathering infrastructure but the more complex and highly dynamic nature of load growth patterns. Forecasting of smart distribution systems must consider the following aspects:

1. <u>Smart meters and energy consumers.</u> Smart meters and appliances combined with advanced energy controllers will allow users schedule, control and optimize energy consumption to minimize cost and attend utility requests during emergency conditions. This will increase demand volatility and the complexity of load forecasts.
2. <u>DER and new loads.</u> Proliferation of DG, Distributed Energy Storage, Demand Response and PEVs and the implementation of concepts such as microgrids and virtual power plants are starting to drive important changes in the way distribution systems are planned and operated. For instance, bidirectional power flows and intentional microgrid islanding may become common in future distribution systems. This evolution would be accompanied by challenges as well. In the specific case of spatial load forecasting, if the annual rate of growth of DG in a small area is greater than that of load the overall effect could be a small area peak load decrease. If DG proliferation is not homogeneous but localized in clusters spread all over the service territory a complex combination of positive and negative annual peak load growth may be observed. This is only one of the possible interactions between existing load and DER. If PEVs, Distributed Energy Storage, Demand Response and microgrids are added to this mix even more complex interactions may occur.

3. Smart distribution systems. Increased reliability and efficiency requirements are spurring the implementation of Distribution Management Systems, real-time monitoring and control, and advanced protection, Volt-VAr and Distribution Automation schemes. The growing utilization of these technologies combined with some of the concepts previously described, for example, microgrids, may lead to more frequent system reconfiguration. This could lead to a variety of feeder topology changes along the year, which would end up affecting spatial load forecasts based on equipment areas such as that shown in Figure 3-4.

Conceivable under the aforementioned dynamic system conditions annual peak load forecasting, even at equipment level, may not be sufficient to effectively plan future distribution systems. Such active grids would inevitably lead to a paradigm shift from annual peak load forecasting to weekly, daily or 8760 hour-based peak load forecast, which would bring the boundaries between distribution planning and operations closer. Accomplishing this goal would require of load, electricity price and weather data, new load forecasting methodologies (for example, hybrid short-term and spatial load forecasting[86]) and software tools, and powerful data processing, communications and computing capabilities.

At the current, and still early, stage of this progression, the need for higher time resolution load forecast is yet incipient. Hence, in most applications utilities can still rely on annual peak load forecasting, as long as consideration is given to model the early stages of adoption of smart technologies. Numerous load forecasting techniques depend on the analysis of historical data to identify load growth patterns and trends that can be extrapolated into the future. However, in the specific case of smart technologies, this is not possible, since historical data that includes the effect of these technologies is simply not available yet.

This impasse can be overcome through assumptions and simplifications that are dependent both on the particular technology under consideration, and the specifics of the utility system under study. Chapter 6 presented a series of examples and demonstrations that illustrate how some of these assumptions and simplifications can be tackled, and how they can be utilized to generate spatial load forecasts. As adoption of smart technologies increases and transcend into maturity a transition from annual to hourly-based load forecast is foreseeable to occur and be accompanied by a corresponding upgrade of enabling systems, methodologies and software tools. It is important that the power industry and utilities and software developers in particular are aware of these expected changes and take a leadership role in preparing for this transition.

[86] STF for hourly/daily operations (for example, DER dispatch) and spatial load forecasting for the longer term load growth pattern identification required for capacity planning

Table 7-1
Forecasting Software Survey[87]

Product	Publisher	Operating System	Platform	Software Capabilities		
				Automatic	Semi-automatic	Manual
Actuarial Forecast Software	Problem Solving Tools	Windows, Mac OS	Excel workbook works on both			y
Analytica	Lumina Decision Systems, Inc.	Windows 7, XP, ME, 2000, MP, NT, 98	32bit or 64-bit			y
Autobox 6.0	AFS	Windows, UNIX,AIX,SUN, Mac in a PC simulator	32 Bit	y	y	y
Forecast Pro TRAC	Business Forecast Systems, Inc.	All Windows platforms, for example, Windows 7, NT, XP, etc.	Ships with both native 32-bit and 64-bit versions	y	y	y
Forecast Pro Unlimited	Business Forecast Systems, Inc.	All Windows platforms, for example, Windows 7, NT, XP, etc.	Ships with both native 32-bit and 64-bit versions	y	y	y
Forecast Pro XE	Business Forecast Systems, Inc.	All Windows platforms, for example, Windows 7, NT, XP, etc.	Native 32-bit application that runs on both 32-bit and 64-bit operating systems.	y	y	y
ForecastX Wizard	John Galt	Windows XP and Higher	32 bit and 64 bit	y	y	y
IBM SPSS Forecasting	IBM	Windows (XP, Vista, 7); Linux, Mac (Snow Leopard and Lion)	32 bit and 64 bit	y	y	y

[87] This list is a summary of a comprehensive survey updated to June of 2012 and available at http://www.orms-today.org/surveys/FSS/FSS.html

Table 7-1 (continued)
Forecasting Software Survey[87]

Product	Publisher	Operating System	Platform	Software Capabilities		
				Automatic	**Semi-automatic**	**Manual**
iData	MJC2	Most Windows, UNIX and Linux	Most platforms supported	y	y	y
Logility Voyager Solutions	Logility	Windows	32 Bit, 64 Bit	y		y
Minitab Statistical Software	Minitab Inc	Windows 7, XP, Vista	One version works with both 32- and 64-bit		y	y
NCSS 8	NCSS, LLC	Windows XP SP2, Vista, 7	32 Bit, 64 Bit		y	y
OpenForecast	stevengould.org	Cross-platform - only requires Java Runtime Environment	Cross-platform - only requires Java Runtime Environment	y	y	y
Oracle Crystal Ball Suite	Oracle America	Windows 7	32 bit, 64-bit	y	y	y
PEER Planner	Delphus, Inc.	Windows XP	32 Bit	y	y	
PEERForecaster Excel Add-in	Delphus, Inc.	Windows XP and up	32 Bit	y	y	
PSI Planner for Windows	Logistics Planning Associates, LLC	Windows (all versions)	32 or 64 Bit	y	y	y
RoadMap Global Planning SystemÂ	RoadMap Technologies	Windows	32/64bit	y	y	y

Table 7-1 (continued)
Forecasting Software Survey[87]

Product	Publisher	Operating System	Platform	Software Capabilities		
				Automatic	Semi-automatic	Manual
SAS Forecast Server	SAS	All major PC, Unix, and Mainframe operating systems	All major platforms supported	y	y	y
SmartForecasts	Smart Software	All Windows Operating Systems	one version works with both 32 and 64 bit systems	y	y	y
Smoothie	Demand Works Co.	All Windows Operating Systems	32 and 64-bit	y	y	
Statpoint Centurion 16	Statpoint Technologies	Windows XP and versions later including Windows 7	32 Bit version works on both, but 64 bit version only works on 64 Bit Windows Platform	y	y	y
SYSTAT	Systat Software, Inc	Windows 7, Vista, XP	32Bit and 64Bit			y
The DecisionTools Suite 5.71 (6.0 Coming Soon.)	Palisade Corporation	Windows 7, Windows XP, Windows Vista	32 Bit and 64 Bit		y	y
Vanguard Forecast Server	Vanguard Software	Server: Windows; End User: Any (including mobile)	One version which works on both	y	y	y
XLMiner	Frontline Systems Inc.	Windows 7 / Vista / XP	32Bit or 64Bit, Excel add-in		y	y

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