A QUANTA TECHNOLOGY WHITE PAPER

Meeting the Load Forecasting and Distribution Planning Challenge of Electrification and EV Adoption

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Introduction

Over the next decade, electric distribution system planning departments at utilities throughout North America will see a major change in the amount of yearly growth of both annual peak load and energy sales. The increasing use of electric vehicles (EV) and the electrification of stationary energy use traditionally fulfilled by fossil fuels, such as natural gas space and water heating, will increase annual peak load and energy growth rates on electric distribution systems throughout North America. These rates will be between 2–3 times what electric utilities have seen in recent decades.

Quite obviously, this increased rate of growth will create a need for more distribution system planning. At most electric utilities, that will mean more distribution planners. This paper will address an aspect of that increasing need for planning that is not generally recognized. While the peak load growth rate in the average US system will roughly double due to changes in the *character* of load growth at the distribution level caused by EV adoption and electrification – specifically the way it spreads throughout the distribution system, affecting the vast majority of feeders – means that the labor involved in some aspects of the distribution planning process *will grow as much as sixfold.* In addition, new types of planning tools and planning methods will be needed to best address that load in an orderly and economic way.

Electrification and EV adoption will affect all U.S. electric utilities but will have their most profound impact on those serving metropolitan areas, where extensive natural gas distribution systems mean a majority of homes and businesses currently use natural gas to meet their heating needs and where the widespread use of large public and commercial vehicles 16–24 hours a day consumes a good deal of energy. Before the end of this decade, most metropolitan electric utilities will see their annual energy sales begin to climb noticeably, and their distribution system peak loads increase slightly each year, an accelerating trend that will last for two or three decades. Many aspects of this increased growth will be good for electric utilities and the power industry in general. Annual energy sales will grow faster than peak load. Load factor and system utilization will both improve noticeably.

This paper is the second of three that Quanta Technology is publishing that examines the challenges created by EV and electrification load growth. Our first white paper discussed the load growth that electrification and EV adoption cause and presented a pair of 30-year distribution-level load forecasts done for a large US city and its surrounding suburban and rural areas—one without EV and electrification load growth and the other with EV and electrification load growth.[1] This paper summarizes the results of those forecasts and then looks in detail at the impact that EV - and electrification - driven load growth will make on distribution system planning needs and processes at electric utilities throughout North America.

This paper discusses the change in the character of load growth that will occur. The systemwide load growth rate may double or even triple in some systems, but the number of feeders that have to be checked annually and for which distribution. Distributed energy resources (DER) or non-wire alternatives (NWA) augmentation is required in order to keep their operation within acceptable criteria, and they will grow by a factor of between 4–6. Distribution planners will have more load growth to deal with, but the growth will manifest itself in distribution upgrade needs as many more projects, on average smaller than the average distribution enhancement projects seen today. The third paper in our three-paper series will focus on the load forecasting and planning methods that can address this type of load growth character, reducing the

[1] L. Willis, R. Masiello, G. Sanchez, R. Fioravanti, and F. Farzan, "Climate change, electrification, electric vehicle adoption, and load growth," Quanta Technology, Raleigh, NC, USA, 2022.

labor needs substantially, and looks at the opportunity that EV and electrification growth create to use DER and NWA in a truly fully integrated manner along with the expansion of the T&D system where necessary.[2]

This paper is organized into five sections. After this introductory section, the next section summarizes the results of the load forecasts covered in our first paper and highlights features of that load growth that affect distribution system planning needs. The section thereafter discusses the change in the character of load growth in detail: what changes, how, and why that is important. The penultimate section discusses the impact that changes in character and other aspects of EV and electrification load growth will have on the workload of distribution system planning departments at electric utilities and looks at five areas where changes to current resources, data, tools, and methodology will be needed. The final section concludes with some recommendations and comments about timing and resource development to meet the challenge of the additional planning work required.

A Representative Distribution Load Forecast for A Typical North American Electric Utility

In order to study the effects that electrification and EV adoption could have on electric load growth, the authors prepared two 30-year feeder-level load forecasts of electric peak load and energy sales for a utility system in the United States. One forecast included all expected effects of load growth over the next three years except EV adoption and increasing rates of electrification. The other includes all current growth factors and EV and electrification.

Not Accurate, but Representative

That load forecast is not represented as being accurate for the system modeled or any area of the U.S. There is simply too much uncertainty about emerging technologies, future potential clean air legislation, adoption trends for EVs and electric appliances, and too much variation in load characteristics and load growth due to different climates and demographics across the U.S. for any forecast to be "accurate" in this context. But the authors do believe that forecast is *qualitatively representative* of the load growth and system effects that electric utilities throughout North America can expect to see over the next 10–30 years due to electrification and EV adoption.

Electrification and EV adoption trends were modeled as growing from 2022 levels of 3% of vehicles sold each year being EVs and 17% electric heat in the modeled system along a Gompertz ("S curve") trend, reaching a market penetration of 80% sales of new units for both electrification and EVs by 2052.[3]

[2] L. Willis, R. Masiello, G. Sanchez, R. Fioravanti, and F. Farzan, "Evolving Distribution and DER/NWA Integrated Resource Planning Needs and the Methodologies to Meet Them," Quanta Technology, Raleigh, NC, USA, 2022.

[3] The forecast reported here was completed in January 2022. At that time the authors stated in the initial draft of this paper that the 80% figure was "near the high end of what is expected in [a cross-section of projections by governments and Wall Street]" of EV and electrification by 2052. However, in the intervening nine months, the fast-moving EV industry has changed, and that 80% figure no longer seems optimistic, but rather at the center of current projections of adoption rates. The forecast for electrification (mainly heat pumps replacing natural gas space heating) is more problematic. Although some states and cities have taken steps to reduce, discourage, or eliminate combustion-based space heating in the future, 20 states have legislation barring cities in their jurisdiction from passing regulations that bar the continued use of natural gas, and several have policies that if not actively promoting its use, do nothing to discourage it. As a result, electrification will proceed at very difference rates in different parts of the country. Planners should also keep in mind that, depending on how one defines "electric space heating" use 15%–20% of electric heating in the U.S. is already done with electricity, and without subsides, roughly 1.5%–2% of the remainder are converting to heat pump use every year. Again, as a national average, an 80% figure does not seem unreasonable for 30 years from now. The caveat there is that due to local regulation, politics, and policy, your results may vary from that national average.

The service territory studied was a 15,000 square-mile area that included a large U.S. city along with its suburbs and sufficient surrounding countryside to compare impacts inside and outside of the metro area with its natural gas distribution network. National averages were used for all factors in order to make the forecast as representative as possible of expected national load growth trends. Climate and weather data used was for the mid-latitude non-coastal eastern U.S. that was adjusted for expected global-warming trends. Again, this was as close to a national average as the authors could find. The peak load was normalized to 90/10 weather in both winter and summer.[4] The load forecasts were done using a load forecast tool designed for the forecasting of load and energy on metro-suburban-rural distribution systems.[5] More detail on the data, assumptions, and forecast method and its results can be found in the paper referenced in the first footnote.

Comparing Load Forecasts with and without Electrification and EV Adoption

Table 1 (parts A and B) compares the two forecasts' load and energy growth during the 30-year period. Figure 1 plots the data from Table 1B. The forecast summarized in Table 1A is a continuation of recent national trends and averages for population, jobs, load growth, and demographic change *without* EVs and electrification included. The population grows by 17% over the 30-year period, and the number of utility customers grows by 23% (the difference is due to demographic and economic factors affecting most U.S. cities). What may surprise many readers is that in that case system's peak load grows by only 0.66% over the 30-year period. This is due to the conjunction of a gradually falling national population growth rate with a continuing long-term trend of annual improvement in electric energy efficiency. Over the past seven decades, the population growth rate has gradually but steadily fallen from more than 1% annually in the 1950s to less than 1% today, while technological improvements and regulation of energy efficiency have led to a steady annual reduction in energy use to achieve similar rates of lighting, heating, and cooling which long-term average is about 0.5%/year. That small annual percent energy efficiency improvement results in a 16.2% decrease in power usage over the thirty-year period, almost completely balancing out load growth due to a population growth rate of 17%. Despite this, during the 30-year period, at the feeder level, utility planners would have to make additions of roughly 8%–10% to their system to serve new customer loads, not within the reach or capacity of their existing distribution system.

Table 1. Peak Load and Energy Growth From 2022–2052 for the Modeled System

1A. Without Electrification and EV Adoption			
Factor	2022	2052	Growth
Population	3,300,000	3,861,000	17%
Customers	1,550,000	1,906,500	23%
Annual energy sales—GWh	44,000	44,300	<1%
Annual summer peak load—MW	8,700	8,750	<1%
Annual winter peak load—MW	7,300	7,350	<1%
Annual peak—MW	8,700	8,750	<1%
Annual load factor	0.57	0.57	-

[4] 90/10 weather is temperature, humidity, sunlight, and wind conditions that create load levels seen or exceeded only one summer per decade, and the same for winter conditions in that season.

[5] See *Spatial Electric Load Forecasting—2nd Edition* by H. Lee Willis, Marcel Dekker, 2002. The algorithm is an improved version of that described in Section 15.5, with the ability to generate 8,760-hour load curves for each feeder.

1B. With Electrification and EV Adoption			
Factor	2022	2052	Growth
Population	3,300,000	3,861,000	17%
Customers	1,550,000	1,906,500	23%
Annual energy sales—GWh	44,000	89,100	103%
Annual summer peak load—MW	8,700	11,750	35%
Annual winter peak load—MW	7,300	15,500	111%
Annual peak load—MW	8,700	15,500	78%
Annual load factor	0.57	0.63	21%

The forecast covered in Table 1B includes all those trends and driving forces modeled in the "without" forecast, plus the EV adoption and electrification of stationary fossil energy applications discussed earlier. The differences between the two forecasts are attributable to the combined effects of electrification and EV adoption. Figure 1 shows the growth trends for energy and summer and winter peak load for this growth scenario. By the end of the 30-year period, assuming planners have done their job and the system is up to it, it will be serving 23% more customers and delivering a bit more than twice the annual energy it did in 2022. The summer peak will have grown noticeably, but the winter peak will have grown to exceed it, with an annual peak now occurring in winter that is far greater than 2022's annual (summer) peak load. The system load factor will have improved from 0.57 to 0.63.

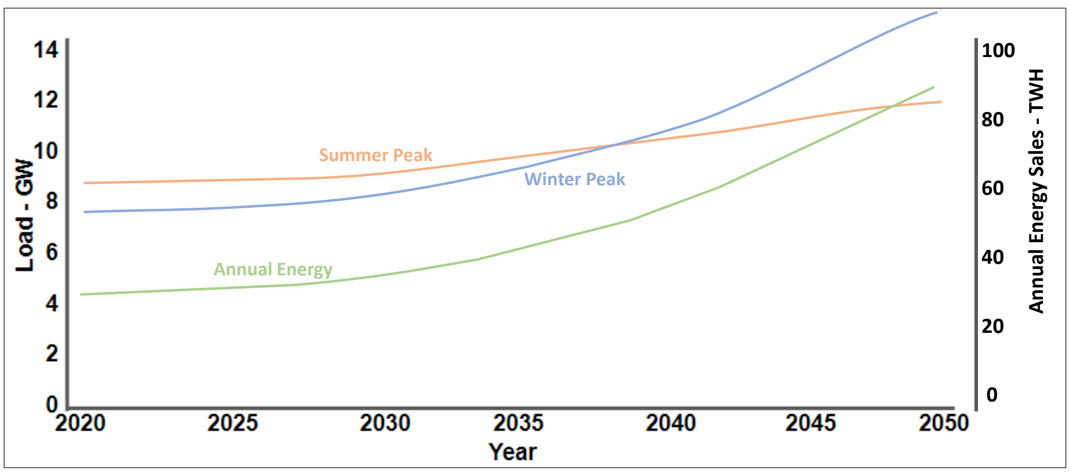

Figure 1. Growth Trends for Summer and Winter Peak Loads

An Interesting Conjunction of Load Growth Drivers

Table 2 shows the breakdown of the system peak load growth over the 30-year period by cause for the "with EV and electrification" forecast, giving the percent of the total net increase in system peak load attributable to each cause.

Long, Slow, and Steady Trends for Both EVs and Electrification

Even if all car buyers switched to buying electric cars now (where 100% of all new vehicle sales are EVs, starting in 2023), since new cars replace existing cars at a rate of only about 3%–4% annually, it would take about 30 years to replace America's current fleet of fossil-fueled of road vehicles. Electrification will play out at a similar or perhaps slightly slower pace. Dramatic as these changes are when viewed over several decades, they proceed at a (relative to the eventual total) slow rate over time. Still, the expected long-term growth due to EV adoption and electrification is so large that a small portion of it is seen every year creating a significant increase in peak load and energy growth rates compared to the recent past.

Table 2. Breakdown of Peak Load Increase Influences 2022–2052 (Percentage of Total Net Load Growth)

Peak Load Increase Influences	Growth
Customer base growth	17%
Global warming effect on winter (annual) peak load	-21%
Energy efficiency improvement on annual peak load	-16%
Winter space heating impact of peak load	75%
Increase in water heating on peak load	19%
EV use impact on peak load	22%
Growth of other per-customer uses	3%
Total	100%

No Effect until Just before 2030

Figure 2 showed the projected growth rate in annual energy sales and summer and winter peak loads for the "with" load growth scenario over the 30-year forecast period. Until around 2027, electrification and EV adoption trends in the "with" forecast make only barely discernable impacts on system load and energy growth. Beginning in 2028–2029, the growth rates of electrification and EV adoption begin to add noticeable increments of load each year. By 2033, electrification and EV will create as much growth in annual energy sales as all other causes of growth combined.

Eventually, an Abrupt Change to Winter Peak

Despite the significant increase in annual energy sales, the annual system peak load during the period from 2027–2038 is projected to grow at a much slower rate, gradually ramping up from that initial 0.75%/year rate in the early 2020s to about 1% by 2035, because EV adoption and electrification have only a modest impact on summer peak load. But during all that time, the winter peak load has been growing 2.5 times faster than the summer peak, playing catch-up, and still not greater than the slowly growing summer peak. This changes abruptly around 2038: the 90/10 winter system peak becomes greater than the 90/10 summer system peak load. After that year, planners see the full effect of the higher winter peak load growth rate on planning needs every year: roughly three times what it had been up to through 2037.

Dual Seasonal Peaking and Seasonal Peak Uncertainty for a Period

For several years before and after 2038, the system will be dual peaking, meaning the 90/10 to 10/90 range of possible summer and winter peak loads due to extreme weather overlap. The observed annual peak load on the system during that period will likely fluctuate back and forth between the seasons for several years during this period due to the vagaries of weather.

Concentrated EV Fleet: Hot Spots

A majority of the aforementioned electric vehicle load in most utility systems will be spread broadly across the electric distribution system, a portion of it in nearly every feeder area. But a substantial minority of that load, up to 40% in some systems, will be concentrated in a few areas of *very intense local peak loads,* which, fortunately, almost invariably will peak at times far from the time of local neighborhood and system peak. These are the locations of commercial vehicle fleets. Commercial vehicle fleet operators (such as Amazon, UPS, and FedEx), large wholesale shipping companies, retail chains (like Walmart and Best Buy), and over-the-road-trucking companies have a compelling economic incentive to convert to electric vehicles early and most probably will. Commercial vehicles like these companies operate are driven 3–4 times farther each year than the average person's car or light truck, so the annual “fuel” savings from electric power is substantial. In addition, the start-and-stop nature of many of these vehicle schedules is very hard on internal combustion drivetrains, but electric vehicles tolerate that service well, requiring much less service. Electric vehicles have a much lower cost in such applications. As a result, many big fleet owners are rushing to convert to EVs as fast as they can.

Most of these fleet hubs are clustered around major transportation hubs and corridors, near the air, ocean, and river ports, or near major railyards and/or major highway intersections. In such places, there can be concentrations of distribution centers, warehouse stations, and shipping centers which cumulatively have hundreds, even thousands of such vehicles and their chargers clustered in a square mile. Most will be charged at night, filling their batteries for use during the next day’s delivery schedule. The load will be off-peak, but it will be intense—up to 500 kW per acre.

A Change in Character of Load Growth as Important as the Increase in Magnitude

This paper was written because the authors believe the industry does not recognize the full extent of the change distribution planning departments will have to make in the near future in order to handle the load growth discussed above. The increase in energy and peak load growth rates that EVs and electrification will make is something everyone recognizes will increase the amount of work planners have to do. But the industry does not seem to recognize that a higher rate of growth will not be the major challenge distribution planning departments face. The *character of load growth* is about to change in a way that will be difficult for current load forecasting and distribution planning methods to handle well.

Electric load in a utility system can grow from one year to the next due only to one or two causes. Either the utility gets more customers during that year through *customer-base growth* (there are more people buying power from the utility this year than last) and/or *customer-usage growth* (there is an increase in the per capita use of electric power[6]). Figure 2 shows the breakdown of peak load growth nationwide in the decades since 1950 by these two causes, along with that projected by the authors, based on the load forecast discussed above and other studies, for the next three decades.

Electric utilities across North America have always seen and probably always will see a noticeable amount of annual energy sales growth due to a growing customer base. This is shown in Figure 2, whether due to customer-base growth (dark green) or growth driven by increases in per-customer usage (light green). The population has grown consistently since the end of World War II, with annual growth rates in both the United States and Canada gradually falling from over 1.5% annually in the early 1950s to about 0.5% today. That population growth—shaped by demographic changes, in and out-migration among regions, and economic expansion—has fueled steady customer-base growth for electric utilities throughout North America for the past seven decades, as Figure 2 shows. There is no reason to think that trend will stop any time soon.

An important distinction to make with respect to customer-base growth is that it does not include all “new customers” a utility sees, only the net increase. A homeowner who moves into the area and buys an existing home is technically a new customer (a new account) to the utility. But the house they bought existed prior to their purchase. They are displacing a customer who was there before. While the daily pattern of

[6] Variations in electric usage due to weather and changes in the economy, which can cause year to year fluctuations in peak load, are not normally counted as “growth.”

consumption of the new owner may differ slightly from the prior owner, the house, its insulation level, and heavy electric loads (HVAC, etc.) remain broadly similar even if the new owner has slightly different habits and usage patterns. The load before and after a change in ownership is similar enough that the change is usually indistinguishable from a distribution system performance standpoint.

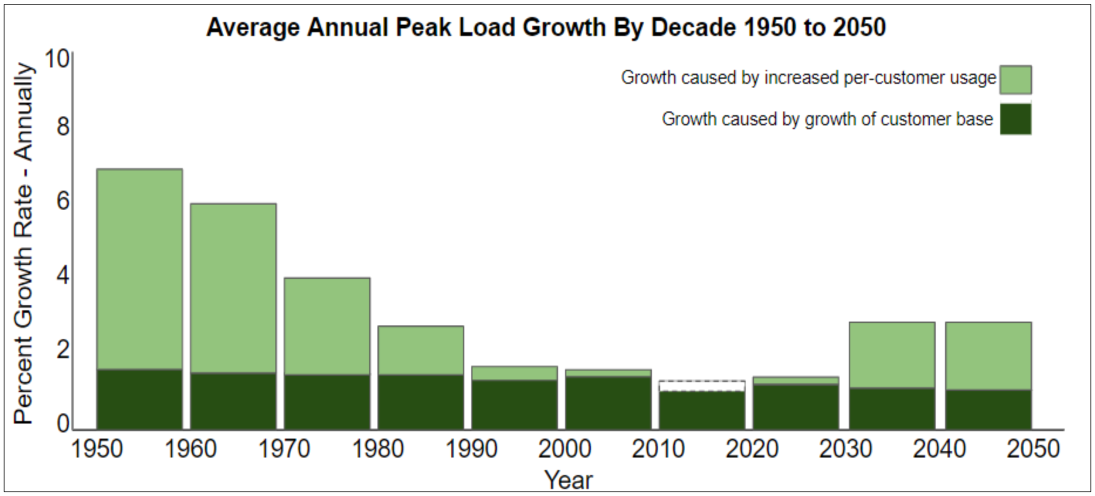

Figure 2. Average Peak Load Growth Rates of American Electric Usage by Decade

What matters is new or changed consumption points. A new home built as part of a new subdivision on previously vacant land along the periphery of the city, a 28-unit multi-story condo built on a site previously occupied by 3 small single-family homes, or a 46-story mixed-use (retail, office, residential) tower built were an 18-story hotel had been for decades before. Those new customers represent *net increases* in the customer base: customer-base growth. It is, thus, the new construction of buildings that is tracked to identify new customer growth.

Laid on top of the load growth caused by customer-base expansion is load growth caused by customer-usage expansion (light green in Figure 2). In the 1950s and 1960s, customer usage load growth far exceeded that due to customer-base growth. The post-war economic and technology boom meant Americans acquired additional electric lighting, kitchen, and utility room appliances; consumer and business electronics; and electric equipment in increasing numbers each year. This led to sustained growth rates of electric peak load just due to per customer-usage growth of over 5% annually in some systems. In the 1970s, just as the market penetration of additional lighting, appliances, and other electric uses was tapering off as their use reached market saturation, the increasing use of air conditioning created an additional surge of electric peak load growth lasting two decades—even more per customer (per capita) increases in electric usage. By the mid-1980s, Americans had nearly all the appliances, electronic devices, and air conditioners that they wanted and per capita growth in electric usage ground to a halt. In fact, as technology improved the energy efficiency of lighting, appliances, heaters, and air conditioners improved a little bit every year, and newer, more efficient units replaced older units when they wore out or became obsolete, per-customer usage of electricity actually went down slightly each year in some systems, even as customer count increased.

As a result, although a majority of load growth that American electric utilities have seen since World War II has been due to customer usage growth, most utilities have seen almost no customer-usage growth in the last three decades. And because of that, the focus of load forecasting and planning processes, procedures, and methods throughout the utility industry has adapted, so it is focused almost exclusively on only load growth caused by customer-base growth. Methodologies and skills used in the 1950s through the early

1980s to track, analyze, forecast, and plan for load growth caused by customer-usage growth were not needed in the past three decades, and most utilities atrophied. A majority of distribution system planners in the power industry today had never seen a sustained period when per capita electric usage was high, and a majority of utility distribution planning departments do not have the data, tools, processes, and overall methodology they need to deal with it. Yet, within a few years, the utilities will have to deal with more load growth due to customer-usage growth than all the customer-base load growth they now handle. They are unprepared.

The data and methodology utilities used to track, forecast, and plan for customer-usage growth in the 1950s–1980s were crude compared to what modern computerized planning methods can do. But despite that, electric utilities managed to plan their systems in a mostly orderly and effective way. This discussion will get back to what those methods are and where to find information on modern versions of them, but for the moment, it will examine this forthcoming change in the character of load growth and how it will affect distribution planning and expansion needs.

These Two Different Causes Create Two Very Different Spatial-Temporal Patterns of Load Growth

The two *types* of load growth—new-customer load growth and customer-usage load growth—create spatial and temporal patterns of growth that are polar opposites of each other with respect to three qualities important to the distribution planning process. These qualities are the (1) amount of growth, (2) rate of growth, and (3) timing of growth to the extent that they require very different approaches and methods on the part of distribution planners if they are expected to plan systems to handle that growth efficiently and economically.

Rapid Concentrated Local Growth: Customer-Base Growth

Customer-base load growth is almost never scattered evenly over a large utility system but concentrated in a relatively small number of "developing hot spots" scattered around the system, perhaps only several dozen in a large metro area at any one time. This spatial clustering behavior is due to a number of factors, all easy to verify and understand but beyond the scope of this discussion.[7] Each hot spot will show intense load growth for a period from three to ten years until growth there "builds out" (uses all the available land in the area). Then growth will move on – spring up in some other, new, hot spot – perhaps just down the road or across the metro area. As a result, on a system or metro-area basis, growth continues smoothly year after year. In any of those hot spots, the pattern of load growth over time in that area looks something like that trend plotted in Figure 3. There is an initial ramp-up of intense growth, usually lasting from two to five years. Growth then tapers off to next to nothing: the area, now just recently built out with new buildings, will see no further load growth due to new construction for the foreseeable future. Due to energy efficiency improvements, in a decade or so, as equipment installed in the original construction gradually reaches its service and is replaced with newer, more efficient equipment, the electric load will most likely go down slightly every year.

[7] See *Spatial Electric Load Forecasting—2nd Edition,* H. Lee Willis, Marcel Dekker, New York, 2002, Chapter 7, for a discussion.

Table 3. Comparison of Load Growth Patterns at the Distribution Level (by Cause)

Characteristic	Description	Customer-Base Growth	Customer-Usage Growth
Cause of Growth	"Why is change taking place?"	New customers are located in the area: **Greenfield:** New customers (as in residential subdivisions and retail centers) are built in former farmland on the edge of a city. **Brownfield:** Existing small homes are replaced by large-footprint townhomes in an older area of the city. Low and mid-rise buildings are replaced by high-rise in the urban core.	Existing customers are expanding their uses of electricity each year: **1950s–1970s:** Expansion of appliance use. **1960–1985:** More appliances, electronics, and the adoption of air conditioning. **1985–2020:** Very little to no growth in electric usage. **2020–2050:** Adoption of electric vehicles, electrification of space and water heating, and other stationary uses.
Spatial Pattern	"Where will the growth be located?"	Load growth is concentrated in a few local areas, with each involving one or only a few adjacent feeders. This growth affects only a small portion of the feeder system at any one time.	Spread across the entire distribution system, though not smoothly. Some feeders see higher growth rates than others, but typically nearly all feeders see some expected growth.
Growth Pattern	"How fast does the load grow?"	Fast growth. Peak load may double, triple, or grow even more in only 3–7 years, then falls to 0 in the years after.	Slow growth. The peak load annual growth rate for a feeder is typically only 1%–3% a year and varies little from year-to-year.
Timing Pattern	"How long does the growth last?"	Only a short time, with 3–7 years in any one local area, and perhaps up to 10 if the economy slows.	Looks like forever. Usually, several decades of nearly the same growth rate every year.

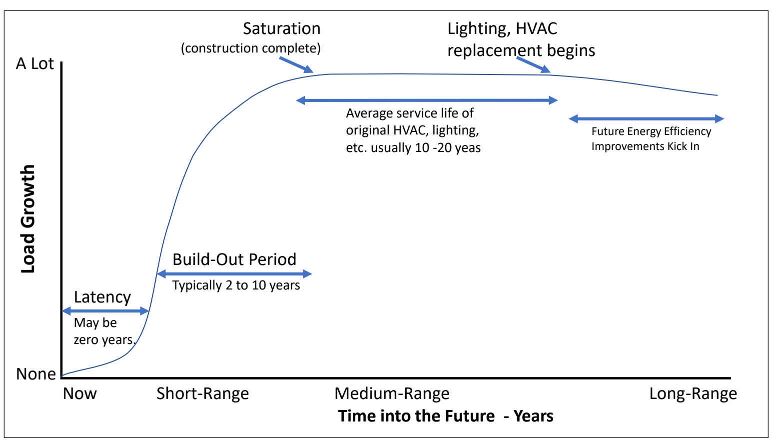

Figure 3. Typical Pattern of Customer-Base Growth in a Developing Area

Hot spots vary in geographic size from smaller than a feeder service area to that covered by several feeder areas. Usually, at any one time, there will be only a handful, even in a large system. The number of developing hot spots, their sizes, and growth rates will vary depending on local conditions and the state of the local economy. When the growth rate is high, the hot spots are not larger, but there are more of them, and they grow more quickly. The long-term process of growth in the system occurs on a continuing basis of nearly the same growth each year because one hot spot "builds out" after a period of a few years to a decade. Growth moves on to other, newer hot spots—maybe just down the street or maybe clear across the system. For example, in the metro system that was used as the base for the author's forecast, the utility dealt with 23 hot spots in the system in 2021. This affected about 9% of all feeders in the system and accounted for 93% of all load growth in the system. Over the past 30 years, the number of hot spots has varied between 14–27.

This is the pattern of load growth that most distribution planners in the U.S., particularly those in large metro areas, have seen for the past three decades. There are observable trends about the load growth trends that are useful to planners and worth considering here. Growth almost always follows the qualitative trend shown in Figure 3 but varies somewhat in every case. There is a position correlation between the amount of load and build-out time: areas with greater amounts of eventual load growth have a longer build-out time. Figure 4. Shows ten different profiles of growth in a metro area in the past decade, illustrating these differences.

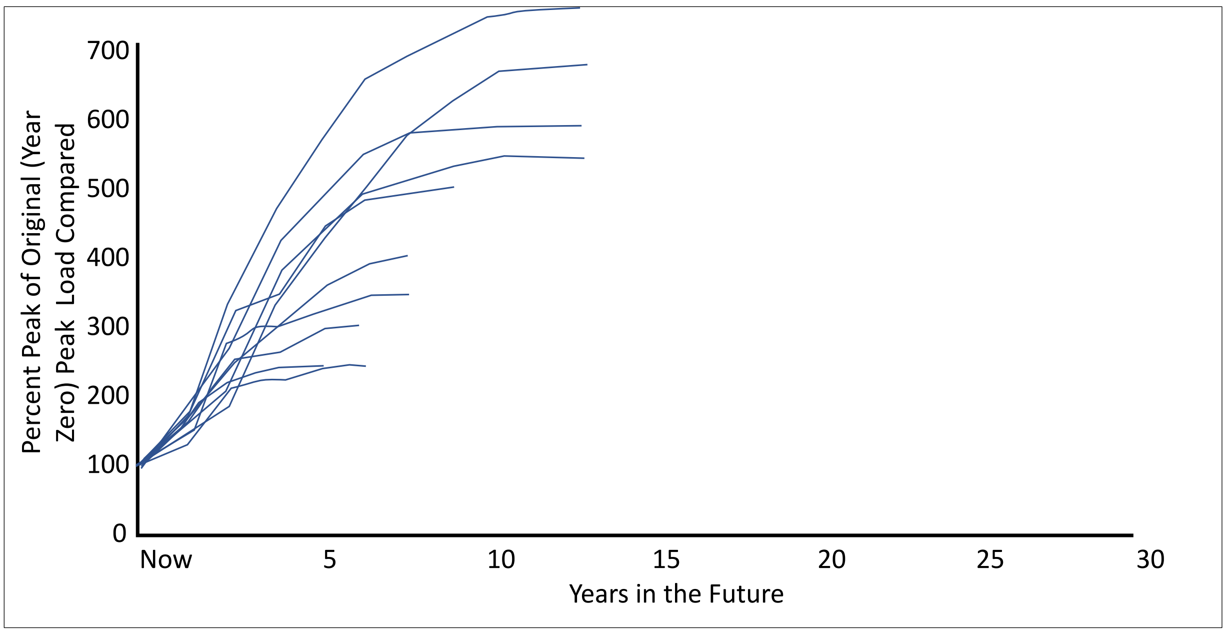

Figure 4. Historical Growth of Load in Ten Areas That Saw Significant Customer-Base Growth from 2010–2022

Slow, Dispersed Load Growth: Customer-Usage Growth

Table 3 makes clear that, from the standpoint of the distribution feeder system, load growth caused by increasing customer usage is the opposite of the pattern of growth caused by customer-base growth in three ways:

- It affects most feeders, not just a few.
- Its local growth rates are never intense, being seldom over 5% annually and often only 1%/year.
- Load growth tends to be steady year after year, for 2–3 decades.

In almost all cases, the amount of growth caused by customer usage growth or change is usually inconsequential unless customers are adopting fundamentally new *uses* of electricity. People buying bigger or more television sets, or an additional microwave for their home, make only a minor impact on load growth, almost always insufficient to affect distribution planning needs. It is the adoption of *new uses* for electricity *en masse* that creates noticeable load growth. Examples are the widespread adoption of air conditioning in American homes and businesses in the 1950s–1980s and, in the future, the increasing adoption of electric cars or heat pumps for space heating. Figure 5 shows an example of the basic profile, which generally follows a Gompertz ("S-curve") shape. It shows the qualitative form of the trend over time, usually exhibited by load growth driven by a new category of customer usages, such as air conditioning in the late 20th century or EVs in the first half of the 21st century.

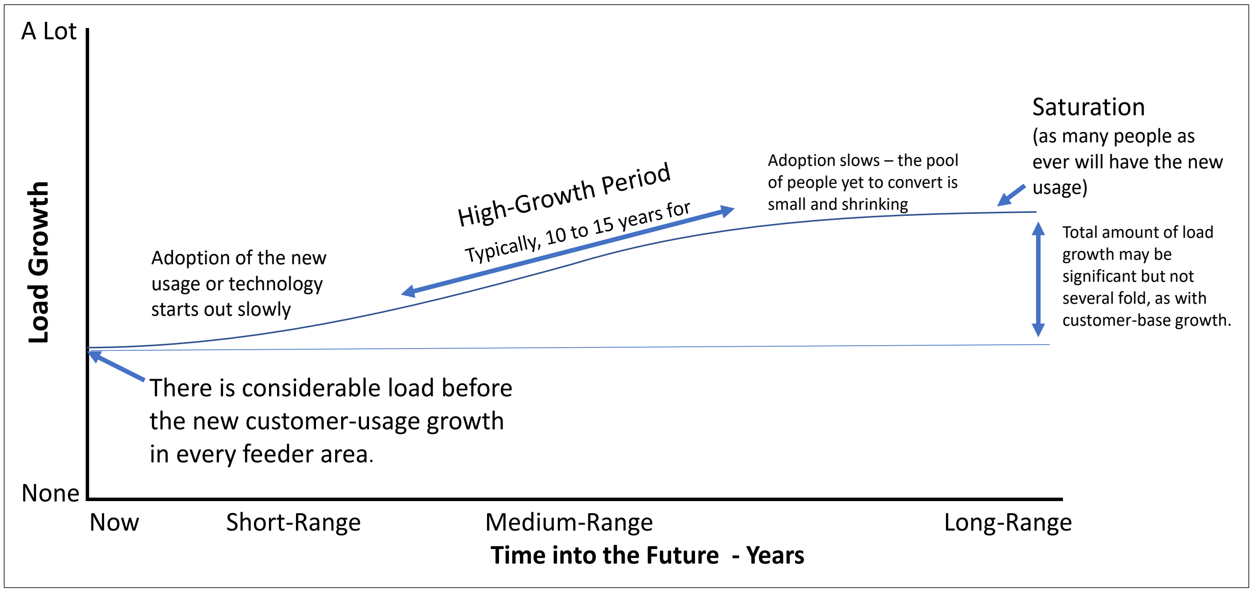

Figure 5. Qualitative Form of the Trend over Time

Although overall customer-usage growth affects most feeders in a system, it is not spread evenly across the system. There can be isolated pockets where it is very concentrated (EV fleet hubs). Beyond those, both the timing and the growth rate of customer-usage load growth may vary a great deal from feeder to feeder because different classes of customers may adopt sooner rather than later. With air conditioning, businesses such as movie theaters and department stores were very early adopters. Other classes followed, sometimes slowly enough that near-complete adoption took over three decades. With EVs, the fleet loads mentioned earlier will be among the first EV load growth to really be discernable to distribution planners. There often is also a considerable difference between the adoption rates of existing versus new customers. For example, nationally, only a small percentage of homes convert from natural gas or other combustible fuels to electric space and water heating each year, but nearly half of all newly built homes in the United States are built with heat pumps. For this reason, most feeders vary from the trend of adoption that might be seen at the system level (Figure 5), perhaps significantly. This will be examined in more detail below.

A Detailed Look at Both Types of Growth and Their Effects on Distribution Feeder Loads

Both the increasing amount of load growth EVs and electrification are expected to cause and determine the way the growth affects different feeders at different times and rates. This is seen in Figure 6, which shows maps of 10-year-ahead load growth on a feeder basis (as projected in by authors with EV and electrification forecast) for a radial portion of the system modeled in that forecast. Figure 6 shows a pie-shaped portion of the study area. The downtown area is to the right, and open country is to the left. The boundary of the gas-distribution system is shown as a dotted line. Expected 10-year ahead peak load growth in fixed feeder areas (kept fixed in this analysis as they were in 2022) is shown as shading for 2022, 2027, and 2032. Feeder service areas are kept constant in these maps, as they were in 2022. Certainly, the load growth shown would cause splitting of feeder areas and construction of new feeders, but for comparison purposes, feeder areas are kept constant in these maps.

The map for 2022 shows the expected load growth planners would be dealing with in 2022 when looking ten years out into the future to 2032. That growth includes roughly the same amount of customer-base growth that planners have seen in the past and only a small amount of load growth due the customer usage. Nascent trends in EV adoption and electrification make a little noticeable impact on feeder peak load growth from 2022–2032. The two feeders marked A in Figure 6 are exceptions. They serve areas near the city's major airport, where UPS, Amazon, FedEx, and other shipping and delivery companies have warehouses and distribution centers with concentrated electric truck charging loads. Similar growth occurs in feeders serving the metro area's port area and near its railyards and a major trucking hub at the intersection of two interstate highways (areas not in the portion of the city mapped in Figure 6). These EV fleet loads are the only EV and electrification load growth trends that will challenge planners in 2022. If they do not catch these growth areas, which will have intense growth from 2027 onward, they will have a tough time playing catch-up later.

Looking ahead to 2027 (the middle map in Figure 6), one sees a map of the load growth planners will be dealing with in 2027 when similarly looking out 10 years to 2037. Again, customer-based growth will continue along the general pattern it showed in 2022 and in the recent past. The hot spots of growth will be moving slightly as it happens over time, but the character of that portion of the load growth will stay the same. The big change compared to 2022 is that a noticeable amount of EV and electrification load growth can be seen. The growth rates for EVs have ramped up quite fast since 2022, and that is for electrification at a somewhat slower rate. While the amount of customer-base growth planners is looking at in 2027 is about the same as they were looking at in 2022, the amount of EV and electrification load growth has tripled.

The map for 2032 shows the load growth that planners for this system would be planning for in 2032, looking out to 2042. Annual load growth created by EV and electrification now exceeds that caused by customer-based growth by a significant amount. Most of the load growth in this system is now being driven by EV and electrification growth.

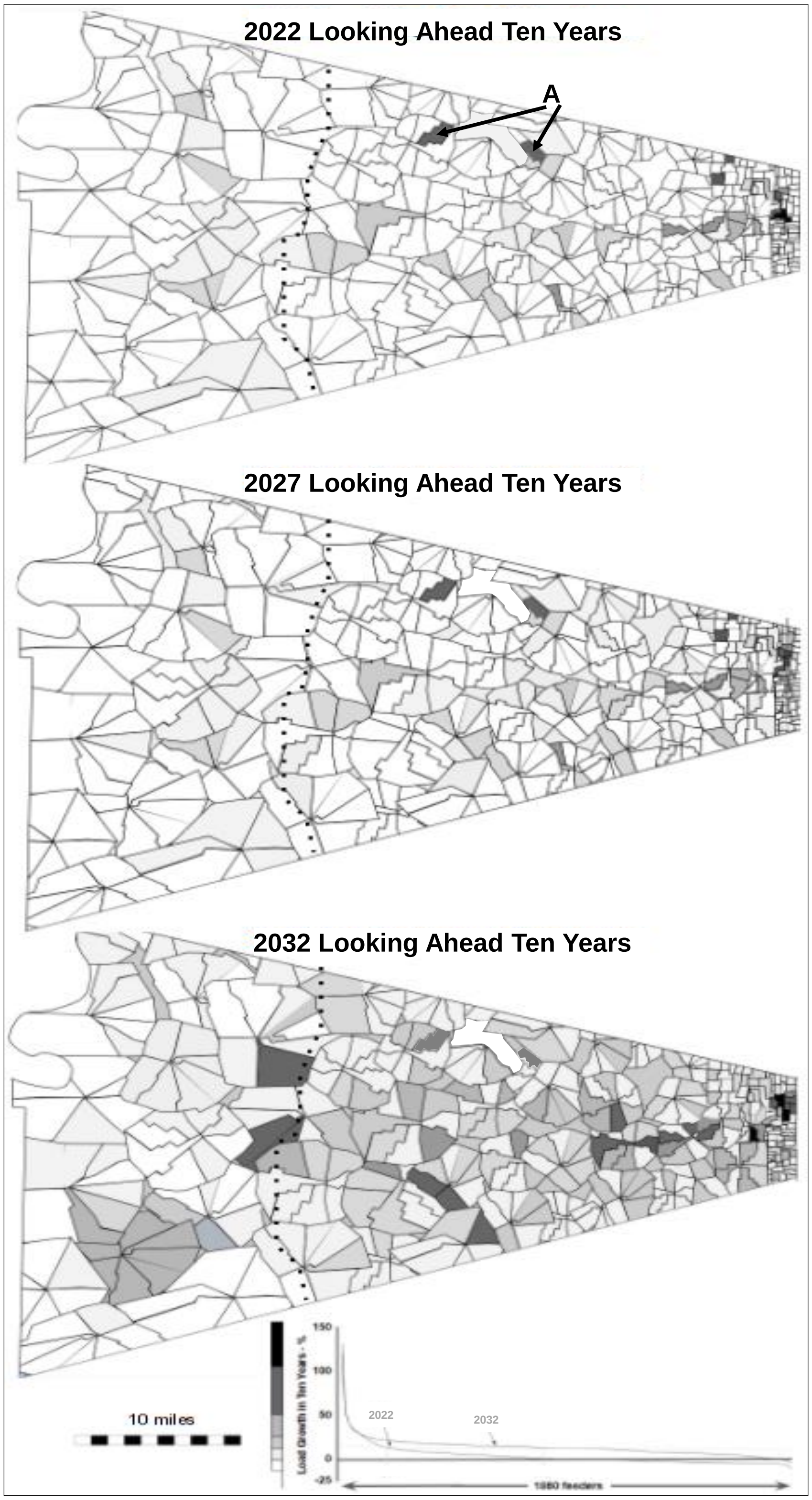

Figure 6. Expected Ten-Year Ahead Peak Load Growth for 2022, 2027, and 2032

The First Big Challenge for Distribution Planning: Growth Everywhere, Every Year

The maps in Figure 6 clearly show that, over time, planners will face more load growth than they did in the past. They also show another characteristic, one that will make a big difference to the procedures, methodology, and amount of effort distribution planners will require to plan for this growth. The number of feeders seeing significant growth skyrockets.

Figure 7 shows two 10-year feeder system growth profiles developed from the load forecast described above. A growth profile is made by sorting all feeders in the system based on their expected percentage peak load growth from highest to lowest and then plotting their growth rates from the highest growth rate on the left to the lowest on the right. Profiles are most useful when they cover a period of several years so that only long-term patterns of significant growth are indicated. Here, the profiles look at 10-year-ahead growth—all the growth expected in the next decade—as the maps in Figure 6 did. The profile labeled 2022 shows the 1,860 feeders in the example system sorted from highest to lowest growth rate based on their peak load growth expected from 2022–2030. There are a few feeders expected to see intense growth, amounting to more than a doubling of their load, in the next decade—feeders in those customer-growth "hot spots" which see intense growth.

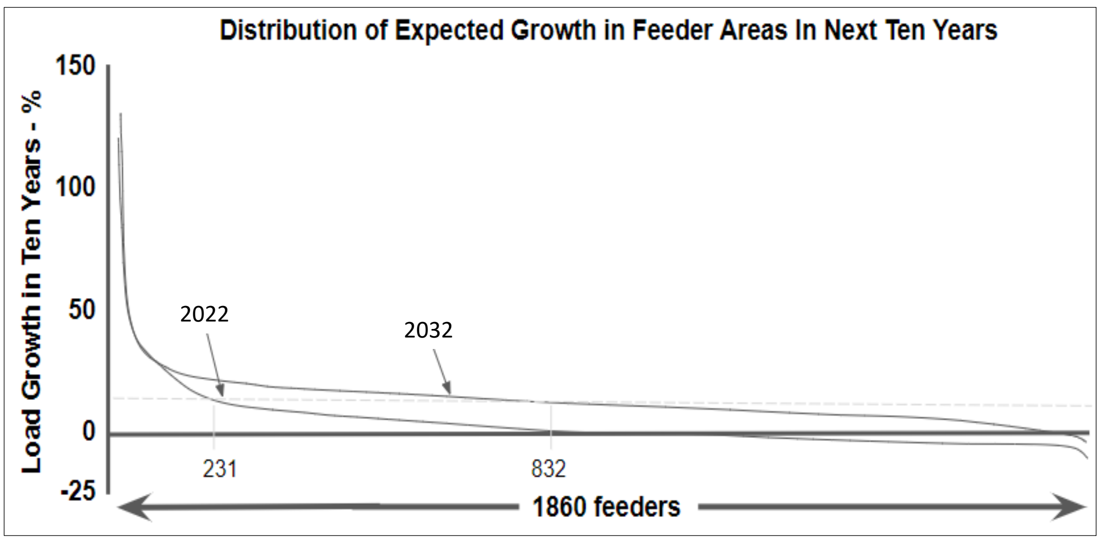

Figure 7. Feeder System Load Growth Profiles for 2022 and 2032

Using a 10% increase in peak load during the next decade as a definition of a "feeder that needs help from planners" produces a count of 231 feeders that planners would need to look at in 2022. This is a measure of the planning challenge planners for this system that planners face in 2022. The profile labeled 2032 shows the same feeder areas[8], sorted from highest to lowest, based on the growth expected to occur from 2032–2042. The number of feeders with "hot spot" growth (those far to the left) does not change materially, as customer-based growth is proceeding as it has in the past. But the number of feeders with at least 10% growth has swollen to 832, which is 3.5 times as many as in 2022, because of load growth caused by EV and electrification. But 2032 is not the worst in this regard. Figure 8 shows that feeders are expected to see a growth of over 10% in the next decade over the 30-year forecast period. It peaks in the early 2040s at 1380 feeders—75% of the system—nearly 6 times the amount of "feeders needing help" in 2022.

[8] To maintain consistency, the authors used the same 2022 feeder areas for the analysis of the 2035–2045 load growth.

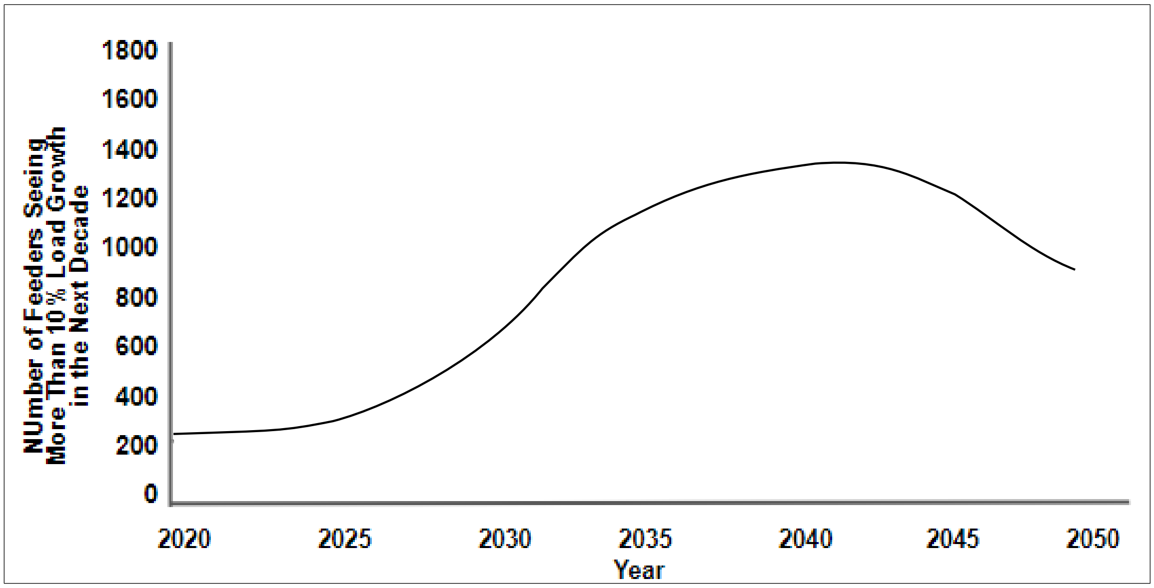

Figure 8. Total Number of Feeders Seeing "Significant Load Growth in the Next Decade" over the Forecast Period

Diversity of Timing of Peak Load Growth on the Feeder System

Figure 1 shows that the annual system peak load in the modeled system shifted to winter in 2038, after which it grew at a considerably faster rate than the annual (summer) peak load had up to that point. Initially, EV and electrification make little impact on the annual peak load, which remains in summer, but during that time winter peak grows much faster than the summer peak, and eventually, it becomes the annual peak load. As explained earlier, from a planning perspective, that change in seasonal peaks and peak load is abrupt, occurring in one year, when the winter 90/10 weather normalized load exceeds the summer 90/10 weather normalized load.

But the trend for the sum of non-coincident weather normalized feeder peak loads is slightly different. There is no abrupt change. Figure 9 shows the sum of annual non-coincident feeder peak loads in the modeled system over the 30-year forecast period (orange line). Unlike the coincident system peak, the sum of non-coincident feeder peaks bends smoothly over a decade-long period. As more and more feeders become winter peaking, its increase in total peak load smoothly transitions to a higher annual rate. This difference from the system peak load behavior is due to considerable diversity in the effects of EV and electrification load growth on feeders in the system due to differences in customer composition and local load curve shapes on the feeder system discussed earlier.

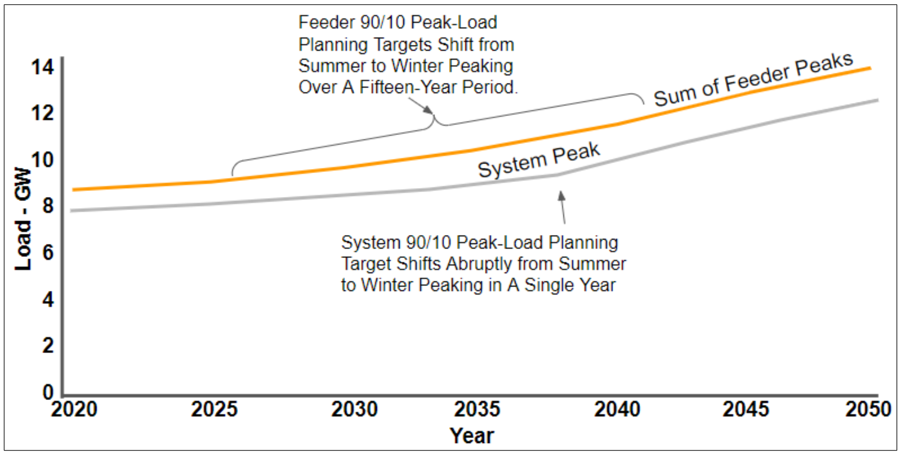

Figure 9. Sum of Non-Coincident Feeder Peaks (Orange) Compared to System Peak (Gray)

Figure 10 plots the peak load growth trend for four feeder areas in the modeled system to show both the diversity of growth trends planners are likely to see and to demonstrate that many of these will be far different that the trend of the coincident system peak. The trend of weather-normalized system peak load growth (dashed line) is compared to that for three feeders in the modeled system that were selected to show the diversity of peak load growth trends expected in the system. These are not rare exceptions. *Most* feeders will differ from the average significantly (Figure 9). At the distribution level, peak load growth is diverse in character and complicated. In many utility systems, feeders with peak load times in the early afternoon will see almost no impact on summer peak loads from EV and electrification loads. Peak load growth and distribution resource additions will not be an issue on those feeders until 15 or more years into the future when the system as a whole evolves into a winter-peaking system. But feeders and utilities with peak loads later in the afternoon or early evening could see noticeable, even significant increases in feeder peak loads, including some cases early in the next decade. The authors believe this diversity of timing and growth trends will be seen in most systems. Feeders will vary in their timing of when they first exhibit a significant change in peak load growth, in how long they remain dual-peaking, and in how much their winter peak ends up dominating the summer peak if any. A small number, slightly fewer than 5% in the modeled system, may never become winter peaking.

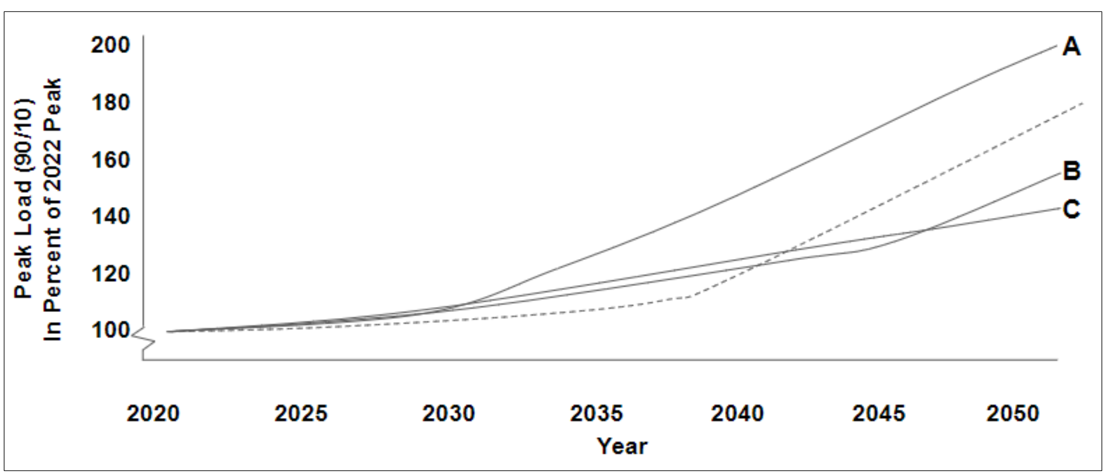

Figure 10. Diversity of Peak Load Growth Trends Expected in the System

Implications for Distribution Planning Departments

Figure 11 shows a simplified diagram of the distribution planning process at an electric distribution utility, which divides the distribution planning process into three major steps. These steps will be used in the rest of this paper to discuss specific areas and effects that the load growth discussed here will have on distribution planning departments and the work they must carry out.

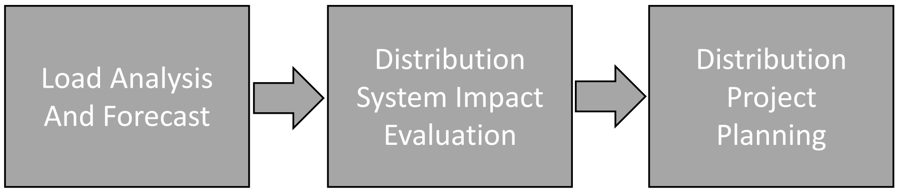

Figure 11. The Distribution Planning Process Viewed as Three Steps

All the Work Done Annually in the Recent Past Will Continue

An assessment of the planning needs for any utility facing load growth like that described in this paper begins by recognizing that the workload the utility's distribution planners have faced in the recent past—load growth driven almost entirely only by customer-base growth—will continue for the foreseeable future. Work those planners have been doing every year for the past several decades will have to continue. Methods and tools used to study and plan for the intensely concentrated patterns of load growth in new developing areas of the system will continue to be needed, roughly with the same degree of effort and concentration in using them as in the recent past.

More Work

Added to that will be an increasing annual workload caused by annual increases in feeder peak load and energy sales driven by customer-usage growth due to EV and electrification adoption. Added to the tools and methods planners have been using to address customer-base load growth will be new tools, techniques, and methodology they need to address the growing amount of customer-usage load growth.

New Load Forecasting Methods

From the 1950s to the early 1980s, all utilities had load forecasting methods that could handle both customer-base and customer-usage-driven load growth. Most utilities have let their methodology and skills in forecasting customer usage growth atrophy for the simple reason that has not been needed in the past several decades. Data, methods, and the required resources to track, analyze, and forecast load growth will need to be added to the existing load forecast capability. This will be discussed later.

Effects of EV Adoption and Electrification Load Growth on Distribution System Load Growth Impact Evaluation

As discussed earlier, the character of the spatial and temporal load growth patterns for EV and electrification-drive growth will be far different than that of the customer-based driven growth planners have faced over the past several decades. This difference will affect both the front end and the backend portions of the planning processes shown in Figure 11 significantly but in far different ways. As shown in Figure 4 and Figure 5, the number of feeders requiring detailed checking in each planning cycle will increase each year gradually until it reaches up to six times what it is today. This step in the planning process will have an added twist of complexity, as demonstrated by far different trends shown in Figure 10. The diversity of feeder growth profiles shown in Figure 10 means that planners will have to check both seasonable peaks routinely, rather than as now, going into the planning process knowing that peak season will remain the same as it was last year, regardless of whether load grows or not.

Distribution Project Planning

The final part of the planning process, distribution project planning, involves developing a set of alternative ways to serve the load without criteria violation, determining which is best, then producing a detailed project plan for that alternative that gives necessary details for the project. Here, the effect of the expected load growth, and its different character, is far more complicated than just "more of the same" as it was for the front-end of the distribution planning process (the feeder load growth impact evaluation).

We will start by looking at this step as it has been performed at most utilities for the last several decades. New-customer growth causes intense local growth rates, often doubling the peak load (or more) in less than a decade. But this is in only a small number of feeder areas, and the majority of feeder areas are unaffected by any growth. The middle part of the planning process, the distribution system impact evaluation, identifies feeders in each of those developing hot spot areas as "needing help," and planners break each developing area as a large project. All the feeders, distribution loops, and equipment (and perhaps the substation serving the area, too) are combined into one planning project to be handled as such through the rest of the planning process. In cases of a particularly large hot spot with a truly large amount of load growth, the project might require a good deal of work spread over several years as alternatives are developed, studied, and refined. Very often, the resulting project calls for almost completely rebuilding the distribution system in the area, perhaps augmented with DER and NWA. Regardless, it is designed to handle the load density the area will have when it is completely "built out." After its brief but intense spur of growth, load growth in this hot spot area is expected to stop (that being the expected outcome of the load growth pattern shown in Figure 3) stops. As a result, planners know that this project plan is essentially a long-range plan for the area: it is considered adequate to serve the load in the hot-spot area for the foreseeable future since it is unlikely that newer construction will replace the newly-built buildings there anytime soon.

This planning project approach will work if applied to feeders seeing mostly or only customer-usage-driven peak load growth, but it is neither efficient nor does it lead to economical additions. The general pattern of load growth that planners will see in such cases is shown in Figure 4, with specific examples shown in Figure 10. It is far different that load growth in developing hot spot areas. First, almost no feeders see intense growth, as load growth is almost always rather modest. To handle their growing load for the next 5–10 years, they do not need intense help, only a little. Second, that growth rate may be modest, but it will last for perhaps 2–3 decades.

If planners wish to maintain a 10% margin of capability above peak weather normalized peak load, then they could expand capability on a feeder, as shown in Figure 12A. This could be done on one project to be completed soon, which adds all the capacity needed for the forecasted future, and lets the load grow without the worry of not having the capability to serve the load for the next few decades. That is efficient, as planners will not soon need to do another project in this feeder area. But it is hardly economical. The majority of capability added will not be needed for years. From a present-worth economics standpoint, this money was spent poorly.

Figure 12B shows another way planners could expand the feeder's capability and maintain the capability to load ratios at a low level. They would develop a small project every few years, each adding only a small amount of capability—just enough to handle the load growth until the next addition. This would not be efficient because it involves a lot of starts- and stop-work and produces a lot of projects to schedule and manage well. But it might be slightly more economical than the single big alternative in Figure 12A, although the start-stop nature of the work, involving so many projects over so many years, would have a cost of its own. Ideally, planners would strike some balance between the two alternatives shown, but that would involve even more work.

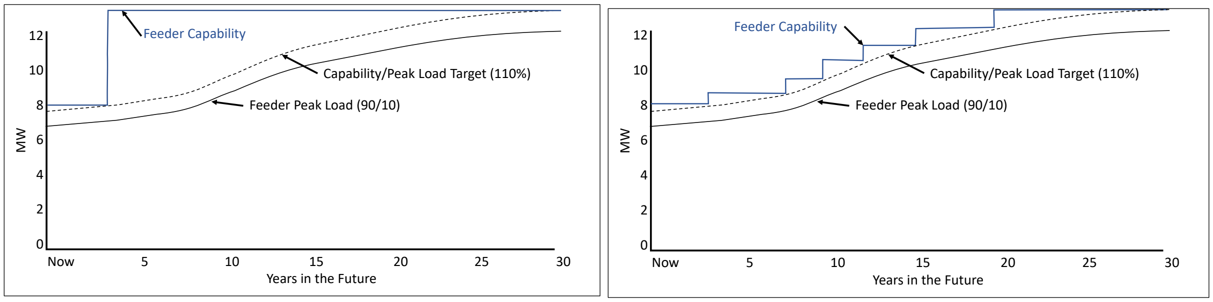

Figure 12. Two Ways the Existing Distribution Planning Process Deals with Feeders Seeing Growth Load: One Large Project (A, Left) and Many Small Projects (B, Right)

A Different Planning Approach is Needed

How did electric utilities efficiently and economically handle distribution planning during the 1950s–1980s, when load growth was last dominated by customer-usage growth? Experienced distribution planners are familiar with the concept of feeder and underground loop splitting (Figure 13). A feeder area that has a growing load is split into two feeder areas via a combination of new construction, reconductoring, and re-switching of the feeder network. Feeder and underground feeder loop splitting is a part of the many major projects that address load growth caused by new-customer additions. While it is perhaps not *the* major part of truly large projects, it is a part of nearly all distribution system upgrades for developing hot spots. Thus, most distribution planners in the industry today are quite familiar with it. Its use in such projects can be considered tactical as a part of a local upgrade of the feeder system.

Past Successful Methods for Handling Such Load Growth: Strategic Feeder Switching

While it is operated as a system of radial feeders, the medium voltage distribution feeder system in most metropolitan areas is physically a tight mesh. It is radialized or looped for operation by a selection of normally open and closed points throughout that mesh. As the load in a group of 10 radial feeders grows by perhaps 30% over the course of time, the mesh in that area can be split into 13 feeders by adding 3 feeders individually as needed. This is done by selectively reconductoring or adding select segments in the mesh, adding or relocating switches, and changing normally open and normally closed points in the mesh to create 11, then 12, and finally 13 feeders.

Figure 14 shows an area in 2025 served by 10 feeders when the area load is 75 MW that is later served by 13 feeders when the load grows by a third to 100 MW in 2040. As the load in that 10-feeder area grows, instead of 10 feeders, there are 11, and then 12, and then 13. Those additions are staged over time to keep the areas' distribution capability sufficient to serve the peak load. Similarly, underground loops in downtown areas are split and rearranged to "add loops" as needed to service additional load.

Done properly, this approach will work well in allowing the traditional planning alternative (expansion of feeder capacity) to be efficiently organized and staged, and relative economical and orderly, even as the entire feeder system sees significant load growth due to customer-usage increases efficient and economical. *A key necessity for this to work well, however, is that the ability of this strategy to work well has to be planned and enabled in a longer-range planning effort than is currently carried out by most local delivery electric utilities.*

It Works, but Planners Have to Look Far into the Future

Addressing EV and electrification load growth well with strategic feeder splitting requires carrying out feeder and loop splitting as a *strategic program,* upgrading the entire feeder system, and employing this method of capability addition on a mass scale over a long period of time. A good part of making this work on a strategic scale is arranging to have the additional substation transformer and bus capacity available as needed to serve those new feeders. The need to make sure that sufficient substation capability is there to serve the growing feeder system and the need to make sure the feeder *system is capable of being split when and as needed* both require a lead time far beyond that used by most utilities today to plan well for developing hot-spot load growth caused by customer-base growth. There, a 5-year ahead forecast and planning process is most common, with a 10-year forecast done as "the long-range" forecast. A considerably longer timeframe is needed when addressing large amounts of customer-usage load growth over a broad feeder system.

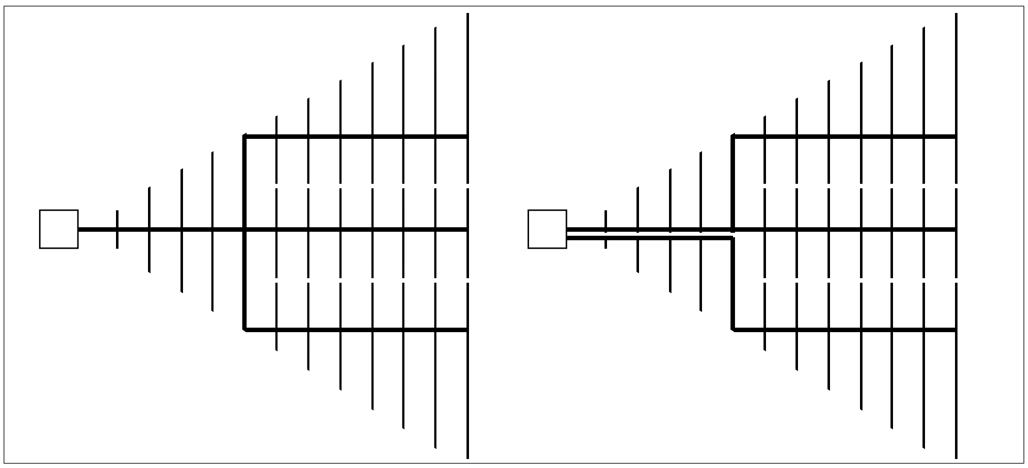

Figure 13. Evolution of a Feeder Expanded in Overall Capability by "Splitting" (2020 with One Feeder and 2030 with Two Feeders)

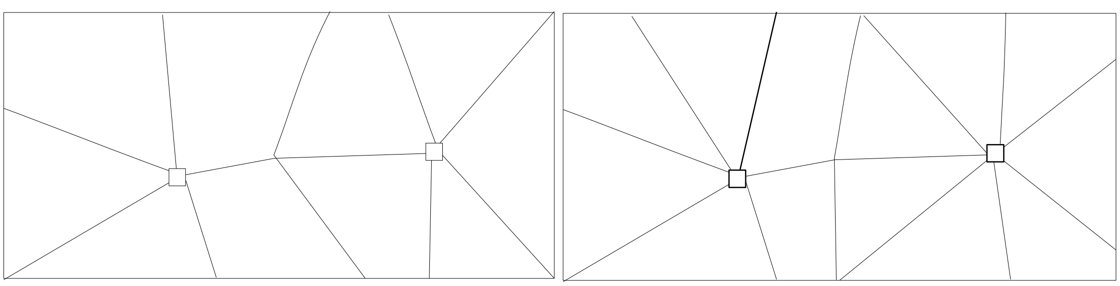

Figure 14. 2025 Area Load of 75 MW Served by 10 Feeders, and 2040 Has 100 MW Area Peak and 13 Feeders

Longer-Range Forecasting and Planning to Support a Strategy of Feeder and Loop Splitting

Utilities made a strategy of feeder splitting and substation expansion work successfully in the 1950s–1980s by forecasting and planning farther into the future than just 10 years and, in many cases developing plans that looked 20–30 years into the future. While sometimes called "30-year plans," those very-long forecasts and plans did not really have a specific year as their basis. Rather, they were horizon-year scenario studies, load forecast scenarios where all "emerging technologies have fully emerged." An advantage touted for this approach in the 1970s was that it is easier to forecast the saturation load (the eventual load a growth trend would reach when complete) than timing (when growth would get to any particular level of user adoption). Long-range planning was set up, not aimed at a specific future year, but *a specific future condition* which was the adoption of new technology or usage is complete. [9] In the 1960s and 1970s, this approach seems far less sensitive to uncertainty when studying evolving air conditioning use. It seems as true with EVs and electrification today.

The horizon-year plans did not require inordinate amounts of additional labor because they were not done with anywhere near as much detail as 5-year and 10-year ahead distribution planning. The goal of this long-range planning was not to actually plan the feeder system or substations thirty years ahead but instead to assure that when the time came, the feeder system could be split and expanded as needed and that substations would be available to feed the growing volume of feeders and greater amount of power they would need. As an example, if long-range planning determines that, eventually, 28 feeder circuits may be needed out of a new substation being built for 2026 with only 10 feeders for its initial load needs, planners should check that, yes, there does not appear to be any barriers to bringing another 18 circuits out of that substation eventually, will not preclude planners eventually added another 18 feeders, and that there is some way to put the required transformers and bus-work into such. Beyond that, there is no need to study anything in the distribution or substation related with more detail. The design of the duct banks and overhead getaway spans or giving any consideration to details can wait until "that time arrives."[10]

DER and NWA Will Help, Probably A Lot, But Probably Only Help, Not Replace, Capacity Addition

Today and in the future, electric utilities and their distribution planners will have DER and NWA available to help them serve a growing load—resources that were unavailable in the past. Potentially, DER and NWA may help mitigate many of the operating overloads and voltage issues future load growth, whether driven by customer-base or customer-usage growth or both, may create on the existing feeder system. They can reshape daily and perhaps even weekly load curves and reduce peak load on feeders and systemwide, perhaps very significantly. As the cost/performance of still-maturing DER technologies comes down and as experience with NWA contractual approaches improves, it is likely more of each will be integrated into distribution system expansion plans, and they will become a larger portion of the resources used to serve future peak load. In fact, they are likely to be very effective in addressing the load growth patterns created by customer-usage increases because they are very scalable and thus could be added in small amounts over time, perhaps more efficiently than could small capacity additions. All planning, but particularly the long-range horizon-year studies that guide strategy, should be done in a balanced integrated-resource manner.

But some significant T&D expansion and augmentation will be needed even if policymakers and regulators were to decide that DER and NWA should be used to the maximum extent possible, not just to their most economical point, before building any new T&D facilities. The reason is that the increase in forecasted energy in some parts of the system exceeds the 24-hour capability of existing feeders. Even if peak-day or peak-week load is flattened completely and rooftop photovoltaics (PV) are hosted to the maximum extent possible, a portion of existing feeders will not have the capability to handle the load or PV hosting capability needed without major upgrades.

Reliability and resiliency will become major issues here, too. As already discussed, the application of electric power to transportation and for additional increments of space heating will increase the need for and value of distribution system reliability and particular resilience for long outages due to storms. Added to that is another factor: the resiliency (or lack thereof) of PV generation, a key DER resource. Along the Atlantic and Gulf coasts, rooftop PV will be a useful distribution resource to use to meet peak load needs. But in areas

[9] See the *Power Distribution Planning Reference Book—2nd Edition,* Section 26.4, "Short- versus Long-Range Planning."
[10] Traditional horizon-year and feeder/loop splitting methodologies for handling this type of load growth are covered in detail in Chapters 14–18 of *Power Distribution Planning Reference Book*, H. L. Willis, Marcel Dekker, 2004.

prone to hurricanes, it cannot be considered a resilient resource, but instead will be one sharing a common mode failure caused by overhead distribution lines. Similar conclusions have been reached in other studies of long-term EV growth impacts on distribution.[11] Still, DER and NWA will prove useful, even critically needed resources. The point here is that the planning will be more complex, requiring more work.

Substation Planning Becomes the Backbone of Long-Range Planning

In the planning approach and process described above, the development of a long-range substation plan (not detailed, but identifying the sites, sizes, characteristics such as access and feeder getaway characteristics, etc.) of needed substations two or three decades ahead becomes part of the central hub of the T&D planning process. It defines the "from" for the feeder planning and provides the information that transmission planning will need for arranging for the future power delivery needs to those substations.

Doing IRP Right

Integrated resource planning methods (IRP) for T&D+DER+NWA that are in use today evaluate IRP options by developing a T&D "solution" first and then attempting to lower the cost of that project by using DER or NWA. Like a gradient-based optimization method that begins with an estimated solution as its starting point and iterates improved solutions until it can find no further improvement, that approach finds an "optimal IRP plan" but often leaves the user wondering if a better plan would have resulted had the "starting solution"— the original plan—been different.[12] The authors are not advocating for any particular approach as much as expressing their doubts that current methodologies work as well as will be needed in the future. Tools used in the future must evaluate all available resources completely and on a balanced basis in cases where a significant amount of T&D, DER, and NWA are mixed and operating simultaneously. Well-integrated resource planning should not be a "sometimes thing" but s new norm, particularly as regards the long-range horizon studies that determine the strategy for the distribution system's resource growth.

Conclusions and Final Comments

It Will Happen

Both EV adoption and electrification of stationary fossil fuel energy usage will happen. Effects and impacts will vary depending on local climate, geography, demographics, economy, and social and cultural habits. The timing, magnitude, and character of peak load and energy growth will differ from one utility system to another. But nearly all utilities are likely to see load growth qualitatively similar to that used in the example system here. Significant impacts will begin to affect their system load growth, and distribution planning needs several years before the end of this decade due to EV and electrification.

The expected changes in magnitude and character of distribution load growth will mean utilities will need more planners, many with new skills and access to data and planning tools their planning departments do not have today. However, the load growth itself is 5–10 years in the future, and the required planning effort that must lead that growth by 5–10 years, or more, is right in front of utilities today. They need to begin

[11]Distribution Impacts of Electric Vehicles: A California Study," Alan Jenn, Jake Highleyman, https://www.ncbi.nlm.nih.gov/pmc/articles/PMC8749456/, and "Will Electric Vehicles Drive Distribution Upgrades?," Jonathan Coignard, et al, *IEEE Electrification Magazine,* June 2019.

[12]In addition, in many cases when the "T&D solution" is developed first, any alternatives are considered later. That T&D solution is evaluated using a traditional planning approach that keys only on the predicted peak load, while the performance and efficacy of most of the alternative resources requires 8,760-hour analysis. The dissonance of the two modeling bases raises further concerns about if in fact a truly "best" solution is always found.

developing these additional planning resources and the planning tools they will require. The authors believe that for most utilities, the priorities will be those listed in the following subsections.

New Load Forecasting Methods

An immediate priority is for utilities to upgrade their load forecasting systems so they can track, analyze, and forecast EV and electrification load growth, as well as their now-forecasted load growth due to new customers. As stated earlier, most utilities put aside methods they had used in the past when customer-usage growth was last this high because they had not been needed for so many years. One cannot blame them. Their situation is analogous to the millions of Americans who once carried routinely carried a spare tire on the trunk of their car but now do not because tire technology means they do not need to: the cost and burden of doing so are no longer needed so, so why bother? But now, something capable of identifying, tracking, analyzing, and forecasting customer usage growth will be needed. There is a rough road ahead otherwise.

Proven, effective forecast tools to do so were used in the 1970s–1980s to forecast broadly similar customer-usage load growth trends seen at that time that were driven by increasing adoption of air conditioning and consumer electronics.[13] The methodology is straightforward, even simple in concept, to the point that it is easily implemented in electronic spreadsheets like Microsoft Excel, which are ideally suited to the structure of the required analysis and modeling. But a considerable amount of intricate recordkeeping and tracking of trends must be included, which takes time and skill to set up and manage and get to function smoothly. The important point here is that while not difficult to implement, most utilities need these load forecast improvements now. Ideally, given the timing of the load growth they face (only about five years from now), they would have them now.

An Initial Horizon-Year Look at Load Growth to Plan the Strategy and the Planning

An early priority is a horizon-year forecast and assessment of need, as was described above, and was done by utilities the last time customer-usage load growth rates were high. A load forecast scenario extending 30 years into the future should look at the consequences of all current trends developing over that period. This would be used for the following purposes:

1) **Long-range strategic plan.** The successful use of a strategic feeder-splitting coupled with staged substation expansion worked well for utilities in the 1950s–1980s because they had planned for it to be feasible years earlier. Whether modern utilities adopt a similar strategy or another—perhaps incorporating DER and NWA as major assets in serving future load growth—their plans will only work if they develop an "enabling plan" that looks far ahead. In essence, at least conceptually, this study of the expansion of the feeder system as a whole due to EV- and electrification-driven growth should be treated as a single systemwide, 30-year project. Again, that plan need not be detailed, but it must be comprehensive, a strategy identified and vetted for the practicality that makes it likely required incremental expansion of the feeder system will be feasible and economical when executed in detail as needed over the next 15–30 years, as was described earlier.

2) **Planning the planning.** In addition, the utility needs to develop a good forecast of the expanded planning workload it will face and when that is likely to occur, so it can plan for the orderly and efficient expansion of its distribution planning capabilities, making sure that sufficient and adequate data, methodology, tools, and skilled planners, are in place to handle it well. This plan needs to develop

[13] See Chapters 4, 16, and 20 in *Spatial Electric Load Forecasting—2nd Edition,* H. Lee Willis, Marcel Dekker, New York, 2002, for a review of methodology and its applications. Websites, such as NREL's end-use modeling site (https://www.nrel.gov/buildings/end-use-load-profiles.html), can provide additional information and sources of data.

various estimates of the timing, the number of feeders that will "need attention" each year, and the number of feeder-planning projects required each year, similar to those shown in this paper for the example system. As was observed earlier, every utility will see slightly different quantitative trends and needs. Every utility needs to study its own future and plan to meet the needs they see for that.

Both plans, for system strategy and for planning resources, need to be done with an objective and balanced integrated-resource approach. If DER and NWA are a big part of that strategy, the utility will need to develop skills, data, analytics, and planning models different than those for strategies without. Every system will likely have some unique requirements that it must take into account. Regardless, a prudent amount of work devoted to this purpose will yield a good payback for the effort.

Increased Value and Complexity of Reliability, Hardening, and System Resiliency

The use of electricity provided by the local distribution system, whether that is power from central generation as in the past, or local DER and NWA as possible in the future, to both power our societies road traffic, and an increase amount of homes and business, will noticeably and perhaps significantly increase the societal, public health, and economic costs of service interruptions and major outages—particularly sustained outages of power of a region as caused by storms, floods, or earthquakes—as compared to what it has been in the past. As a result, the need for and the value delivered by reliability, hardening, and resiliency programs will increase. This, too, could have a noticeable impact both on the amount of planning labor involved and particularly the skills and planning tools needed. That look at future planning needs should include a hard look at the need and role that the planning, engineering, and management of reliability, hardening, and resiliency will play in the future of both the distribution system and the distribution planning department's needs.

Automated and Artificial Intelligence-Based Planning Tools

The greater amount of load growth, and the added complexity of planning DER, NWA along with the increased attention the reliability and resiliency, will increase the benefit/cost of developing and using automated planning tools and artificial intelligence (rule-based, grade-logic, and learning routines) software for integrated T&D and DER/NWA planning. That, and the organization of the planning process around a greater volume of smaller feeder-level projects needed each year, should be able to streamline work processes enough to reduce planning cycle time and cut needed human resources considerably.

Revised Planning Process and Procedures and Resource Plan

The biggest challenge facing distribution planning departments will be designing and adopting a new planning process for feeder system planning that accommodates the needs and growth patterns described in this paper. Armed with the information developed in the work and study outlined in the four steps above, the utility needs to revise its distribution planning process to include longer-range planning and to accommodate the expanding workload it has identified for its system. Guidelines that may help in designing the required processes can be found both in strategy and approaches available in established references.

Now, Not Later

The authors will conclude with a reminder that at least some of the required changes and additions are needed now. Figure 15 shows the authors' best estimate of the overall load growth impact (black line) and the impact on distribution planning department labor and skills needs in the load forecasting and integrated delivery system/DER-DSM/NWA resource planning steps in the distribution planning process, for the example utility system forecast and discussed in this paper. Here, the black line indicates the actual load growth. Forecasting has to lead that actual load growth by at least ten years. Moving the black curve forward ten years, and scaling it proportional to the increase in expected forecast workload, gives the orange line – an indication of when and how much more work utility planners will have to do on load forecasting, and when. Similarly the green line, moved forward five years and scaled, gives some idea of the timing of the additional tools, planners, and skills that utilities will need. The effort required for detailed planning of distribution/DER/NWA resources to follow up those load forecasts and add the capability to the system is only now starting to climb above traditional levels, but it will increase more each year over the next decade, reaching twice the current effort level annually, continuing to grow to about two-and-a-quarter times the work done today about 15 years from now.

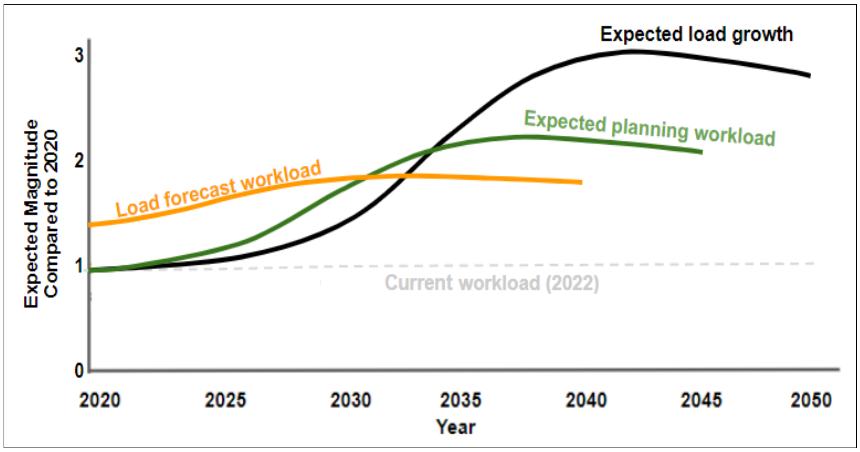

Figure 15. Overall Load Growth Estimate

Revised Planning Process and Procedures and Resource Plan

Armed with the information developed in the work and study outlined in the steps above, the utility needs to revise its distribution planning process to include longer-range planning and to accommodate the expanding workload it has identified for its system. Guidelines that may help in designing the required processes can be found both in the references given in the Bibliography.

What is Needed Now

The authors will conclude with a final reminder that at least some of the required changes and additions are needed now. Figure 15 shows the authors' best estimate of the overall load growth impact (black line) and the impact on distribution planning department labor (work humans have to do as opposed to work that can be done by smart computers) in the load forecasting and analysis (orange), and the integrated delivery system/DER-DSM/NWA resource planning of capability to serve the load (green line) in the distribution planning process for the example utility system forecast and discussed in this paper. The orange and green lines show the labor (human effort) needed to keep up with load analysis and planning that will be needed. Regardless of the type of feeder-system expansion the utility chooses and the use of automated and artificial intelligence-based planning tools, a substantial increase in skilled distribution planners will be needed, and considerably more organization and management of the planning process will be required.

Recommended Reading

Most modern books on power distribution planning and engineering focus on the customer-base-driven forecasting and planning methods applied in the power industry during the last two decades, particularly on the numerical methodology needed, more than on the process. The following references address methodology too but also process and policy are those that might help utilities face the challenges discussed in this paper.

Control and Automation of Electrical Power Distribution Systems, James Northcote-Green, and Robert Wilson, Taylor and Francis, New York, 2006. This book, written for the international power utility market, which includes many developing second- and third-world economies with expanding electrical usage driving their load growth, does not address planning per se except in one chapter, but it is informed throughout with a view of an electric utility's needs when facing considerable growth of customer usage unlike most recent books of power systems.

Long-Range Forecasting: From Crystal Ball to Computer, J. Scott Armstrong, various publishers, and editions. This is *the* classic text on forecasting for business purposes, as developed and taught at the Wharton School for the past five decades. First written when long-range forecasting and planning was a standard part of most utility distribution planning activities, this is an excellent conceptual guide with a good deal of practical advice.

Power Distribution System Planning Reference Book—2nd Edition, H. Lee Willis, CRC, Boca Raton, 2004. One of the few texts the authors know that discusses multi-feeder system and substation planning and expansion as done in 1960–1980s including strategic feeder switching (Chapters 15 and 16, and the design of appropriate forecasting and planning processes (Chapters 20, 24–27, and 30).

Technological Forecasting for Decisionmaking, Joseph P. Martino. Also first written several decades ago, this is the classic text of forecasting technology and the adoption of new equipment and appliances. It was updated from time to time and published continuously for four decades, beginning in the early 1970s by various publishers. All versions are good, but versions published after 1990 are slightly better.

Three-Domain Modeling and Uncertainty Analysis; Applications in Long Range Infrastructure Planning (Energy Systems) Atom Marakyan and Roland De Guio, Springer, New York, 2015. This book is one of the few written recently that addresses long-range planning. It is not specific to electric power systems, but all perspectives and topics apply. A very difficult read, at times quite complex in dealing with subtle concepts, it has insightful nuggets of practical wisdom to guide the planning of energy infrastructures including electric systems and to handle uncertainty in technology and social trend analysis and forecasting.