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Addressing New Challenges in Distribution Planning

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SUMMARY

The accelerated adoption of relatively new, localized, distribution system-based technologies is challenging a growing number of utilities as they plan and implement distribution system investments. As policies and incentives are adopted and foundational technology costs decline, Distributed Energy Resources (DER), energy storage, plug-in electric vehicles (PEV), energy efficiency measures, and targeted energy management solutions are multiplying on a regional and national basis. Customers in many utility markets are now able to select and implement distribution grid-connected DER systems according to their interests, independent of their relationship with their utility.

Many utilities are also facing challenges created from stagnating or declining peak load growth, even with an increase in the number of customers on the system. Distribution planners are facing the additional challenges of increasing criteria related to asset hardening, aging facilities, and more stringent reliability targets and must consider these factors along with traditional planning activities for capacity and acceptable voltage levels. Added complication for distribution planners also arises from the myriad of new systems that provide data to the distribution planner, such as from asset management, outage management, advanced metering, distribution management, demand response, and energy efficiency.

As a result, traditional planning methods require new analytical tools to identify and plan for investments that will prove locational value and outlast the near-term changes impacting distribution systems. Increasingly, utilities must plan for localized generation and loads while taking into account existing constraints and complex, unanticipated interactions between discrete components of the distribution system. **Advanced Distribution Planning** (ADP) is a practice that addresses these challenges and enables utilities to manage system investments with optimized recommendations. This paper will explore these challenges in detail and present ADP as an innovative, revolutionary solution.

KEYWORDS

Distribution planning, distribution system planning, advanced distribution planning, distributed energy resources, load forecasting, spatial load forecasting, non-wires alternatives

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The Challenge: Distribution Planning Shows Its Age

Like the transportation, communications, and entertainment industries, the electric utility industry is undergoing transformative change due to technological advances that give customers new options. The arc of disruptive impacts arising from new technologies over the last 100+ years can be traced with examples such as the evolution of the smart phone from the telegraph, or the automobile from the horse and carriage. These examples are well understood, but stand in stark contrast to the electric utility industry over the same period. While utility distribution system components have certainly modernized and improved, the essential techniques of system planning have seen minimal change. Large, centralized, utility-managed generation has only been required to scale to meet an aggregate system demand that traditionally grew at a nominal annual rate. Likewise, distribution system investments were highly predictable and generally easy to plan based on well understood customer loads and linear rates of change. Utilities have long been able to remain conservative and consistent in their practices. However, the advent of renewable, distributed energy generation and the growing influx of technology on the grid have thrust utilities onto the same arc of change that has transformed so many other industries, and has begun to empower customers to enact that change in ways that disrupt traditional utility business models.

Renewable energy, in its various forms other than hydroelectric, is currently a small portion of the overall electric generation portfolio across the U.S. Regionally, however, solar is increasing in importance and overall quantity. In 2016, renewables accounted for 4.1% of the generation in the U.S., and solar represented only 0.9% of the total, according to the U.S. Energy Information Administration. Trends show that this is likely to change rapidly in the coming years. By 2020, GTM Research estimates solar module prices to drop by 29-36% compared to 2012 prices. This means that solar generation is on a path to be increasingly more competitive.

Distributed solar is also becoming a regionally significant portion of utility generation resources with net metering customer concentrations growing notably in states such as Arizona, Massachusetts, California, Florida, and Hawaii. Since 2010, total megawatt hours (MWh) of distributed solar deployed at U.S. investor-owned utilities (IOU) has more than tripled to over 600,000 MWh with a steep upward trend in the past two years. These trends are driven significantly by state and local policies, but the cost-competitive improvements in photovoltaic technologies are accelerating the growth of solar so that it will impact an increasing number of U.S. electric utilities. Customers and developers see the value and opportunity with choosing solar or other energy resources, and utilities now face competition for generation and delivery on an increasing scale.

The true risk to utilities from increased solar penetration is that system changes planned today will be inadequate, perhaps even inappropriate, within a few years instead of the decades over which traditional distribution system investments are typically measured. This could render the system capital wasted.

Leading regional examples of the solar penetration challenge demonstrate the risks. California and Hawaii have a large and growing solar generation component, both in terms of grid-scale and distributed net metering. This is creating a dramatic load shift, as well as potential issues for the distribution systems where the solar penetration is high during parts of the day when load is low. These load shifts create local system planning and service challenges depending on where generation is sited and the nature of traditional loads at a particular time of day.

Disruption beyond Renewables

Further confounding utilities at the local level are grid-impacting systems such as PEVs and energy storage. It is forecasted that electric vehicles are likely to account for as much as a third of global automobile sales by 2040[2]. Considering that the proliferation of PEVs will be regionally variable, together with consumer behaviors such as clustered buying, the potential for localized, mobile load issues becomes significant. Energy storage is likewise poised to become a major planning challenge with costs projected to continue a rapid decline over the next 12 years. Packaging of storage technology for grid-scale installations as well as consumer premises continues to evolve. It is

reasonable to expect that storage opportunities will significantly increase, impacting distribution planning scenarios in multiple ways such as load serving or ancillary services. Once again, this is likely well within the investment time horizon for utilities specifying changes today.

Utilities must also consider that a multitude of stakeholder interests and improving control technologies are combining to make microgrids a viable reality in a number of potential scenarios. The risk of load defection on a part-time or continuous basis is a real possibility for a growing number of utilities. Also, energy efficiency measures are having an impact upon load growth that many utilities had not planned for. Utility customers now have access to more efficient appliances and new homes are using energy more efficiently as well as customers making efficiency improvements to older homes.

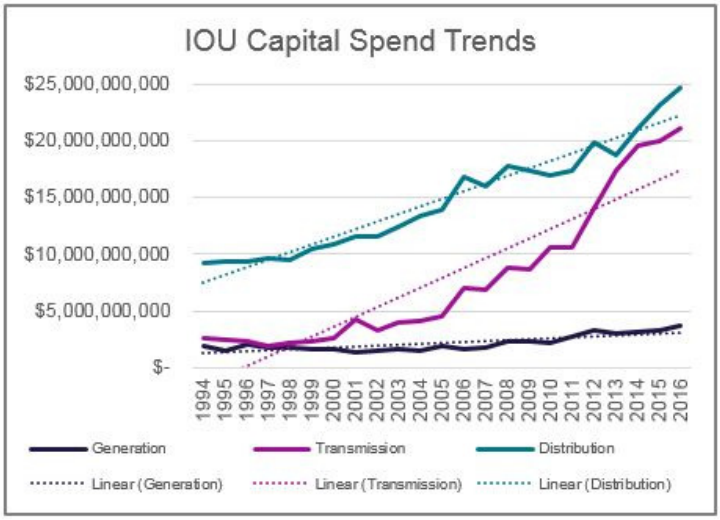
Finally, integrated resource planning (IRP) is the traditional approach to solving the supply and demand equation, but connecting these outcomes to system capital investments is not always a clear path. National Renewable Energy Laboratory (NREL) has concluded some utilities face "continuous refinement" of forecasting methods and that all utilities should include some distributed photovoltaic in their integrated resource plans[3, 4]. System planning methods must address the local, more granular requirements of spatial load forecasting over and above the system-wide IRP.

Because of these trends, distribution system planning is becoming a big challenge. Rather than an aggregate overall system load forecast on a handful of representative dates during the year, load forecasting is becoming increasingly difficult. Load forecasts must now be considered at a locally discrete level taking into consideration a broad variety of scenarios involving such aspects as the grid-impacting systems discussed, customer demographics, weather, economics, energy efficiency, and existing system performance. Based on the number of variables and values to consider, each in a very specific spatial circumstance on the given distribution system, the challenge is a daunting one.

The Widening-Array of Non-wires Alternative (NWA) Options and Placement Methods

As shown in Figure 1, IOU capital spending trends indicate continued increases in distribution and transmission system investments[1]. At the same time, capital investments in generation have remained mostly flat.

Figure 1. IOU Capital Spending Trends



Utilities are pouring money into system modernization using traditional planning methods that are based on overall system demand growth under worst-case scenarios and contingency margins that dictate traditional wires-based investments. Unfortunately, this traditional planning method ignores the likelihood of localized generation and unpredictable loads. Power flows and energy demands are likely

to be anything but business-as-usual well within the timeframe when these sizeable system investments will be paid off. Utilities are now moving to options beyond traditional wires-based alternatives to deliver risk-minimized outcomes. Non-wires alternatives, including programmatic customer services like demand side management and demand response or controls-based options using sensors and software to switch loads and supply, are becoming increasingly capable as a means to defer costly system investments.

Distribution planning is becoming increasingly more difficult from a resources planning perspective as well as for modeling new potential NWA solutions to traditional distribution system planning issues. Technology is moving at such a rampant pace, that utilities in extreme instances are moving to an annual planning cycle as opposed to two- or five-year planning-update cycles. Economic analysis of alternatives of NWA's make the situation more difficult, when considering that technology's rampant pace also makes equipment prices change rapidly. New NWA technologies and innovative planning have created an array of options to add to the list of traditional wired alternatives. Table 1 shows the potential NWA solutions and placement considerations.

Table 1. NWA Placement Methods

Placement Method	NWA Description	Benefits	Drawbacks	Successful Solution Outcomes
Per Customer	Micro distributed generation/ storage (<10kW)	Losses optimized, resource is nearest load. Decentralization maximizes power-on during outages. Pairs well with TOU rate and peak-shaving.	If utility managed, large, new asset class with specialty skills required. Potential for subset of customers to opt-out. High number of stakeholders [5].	Reduce utility peak load avoidance of demand charges. Gives utility customers an energy resource for use in any way they see fit if not in utility-need event.
Dispersed	Small units (<5MW) located near sectionalizing devices	Small unit size and location nearest load provides greater control for loading and voltage improvement during normal system operation. Limit the outage to the smallest number of customers.	Increase quantity of devices increasing communication, control system, and maintenance.	Serves all load downline of the sectionalizing device for which the generation is closest to. Feeder is more flexible and can be dissected into small microgrids as necessary until primary power can be restored.
Aggregated	Medium units (5-10 MW) located past mainline sectionalizing device	More centralized generation limits communication and maintenance costs. Location near load provides utility capability for loading and voltage improvement during normal operation.	Faults occurring in the zone of the feeder protection would likely split the circuit in half. The NWA unit would not be capable of serving the entire feeder for the loss of the substation transformer.	Provides capability of serving all load downline of the main line sectionalizing device. Optimal solution for feeders or sections of feeders with limited ties.
Feeder Ties	Medium units (5-10MW) located between feeder pairs	More centralized generation limits communication and maintenance costs. Limits the outage nearest sectionalizing device to the substation.	Not optimal location for peak shaving or loading and voltage improvement.	Capability of serving all load between feeders. Provides optimal solution between feeders for contingency scenario for which the substation / feeder restoring power is at capacity.

Placement Method	NWA Description	Benefits	Drawbacks	Successful Solution Outcomes
Substation	Large units (>10MW) located at the substation	More centralized generation limits communication and maintenance costs.	No reliability improvement for fault that occurs outside of the substation.	Serves all load served by a substation transformer. Provides convenient method for substation maintenance and potential for mobile deployment to other substations.

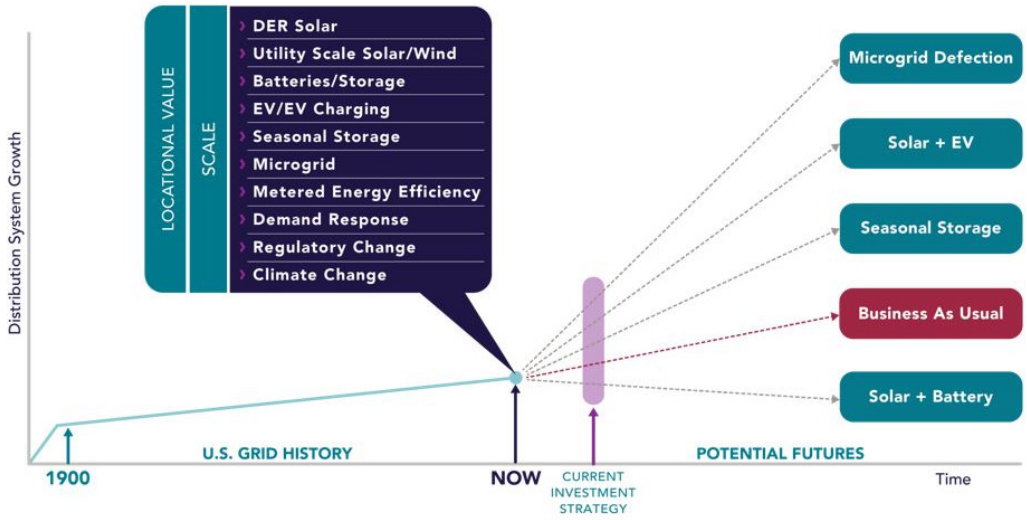
When considering combinations from the already long list of potential wired solutions together with the NWA solutions, the problem for distribution planners to converge on an optimal solution becomes extremely difficult with traditional distribution planning techniques.

Traditional tools and methods work well for predictable large-scale estimation with human effort guiding the process. This time-tested approach has been a straightforward approach to planning for decades. In light of this new complexity, however, the ability of humans to manually consider all possible inputs and outcomes becomes impractical. Simply applying high-level estimates and generous contingency allowances introduces the risk of inefficient, or worse, inaccurate system enhancement plans. Utilities must make investments that will not be paid off until well beyond the change horizon under these new circumstances. Disruptive changes are happening and are expected to continue. The impact of accounting for these inevitabilities is costly. Utilities need new tools and methodologies to address these planning challenges and identify the best-fit, no-regrets solutions at spatially specific system levels.

The Solution: ADP

Given the looming uncertainties about the future of generation sources, customer needs, and aging or inadequate distribution infrastructure, building a defensible business strategy is becoming increasingly difficult for utilities. Decisions must be made now, when the future can present a wide range of outcomes. As shown in Figure 2, traditional planning methods have been quite predictable and methodical for decades. Now, the potential for a variety of alternative futures exists. This creates confusion and uncertainty over how to best spend precious capital and be confident it is applied in a manner that provides the lowest risk, most appropriate solutions, and highest return possible. Considerations of locational value and scale will be imposed on planning practices, creating a challenge around a wide range of potential, locally specific outcomes and a combination of factors that are at the same time technical, economic, and demographic. ADP must not only address traditional system improvements such as transformers, field controls, and conductor adequacy, but non-wires options like customer programs, sensors and software, or control systems. The goal of ADP should be to minimize capital risk while optimizing system outcomes over the planning horizon.

Figure 2. Distribution System Planning Potential Futures



ADP describes a strategy to address risks and identify the top, defensible investment priorities. ADP consists of:

- Leveraging the massive amount of data that utilities now collect to understand current load dynamics
- Creating a range of spatial forecasts, which analyze a broad range of possible future outcomes
- Automating the load-flow analysis to calculate network deficiencies and intelligently match those deficiencies to "wire" and "non-wire" alternative solutions
- Performing economic simulations to understand the best capital strategy that delivers maximum impact and return on investment

Historical Load

Traditional planning evaluates historical load in the context of a total system on critical days based on the general operating conditions of the system. It is typically oriented around weather and specific load drivers such as heating and cooling. Until now, locational value has not been a priority. Contingencies have been achieved with higher factors of safety than necessary and the system planned to meet a relatively strict margin of safety against the unknown. Margin assumptions have been largely experience-based and most modeling was focused on trending peak loads aggregated to the primary distribution circuit breaker. Most utilities in the U.S. know their loads at the substation transformer level, but many still lack telemetry and data-driven forecasts at the distribution breaker level. A lack of data and an inability to operate with complex, granular forecasts drove broad assumptions and investment decisions designed to cover the overall worst-case scenarios resulting from linear forecasts. To add to this uncertainty, many distribution utilities have seen flat or negative peak load growth and are left with unanswered questions as to why the load didn't grow as forecasted. The rate of peak load growth has steadily slowed since the 1970's, but not until the last decade have U.S. distribution utilities faced load growth less than 1% per year[6].

With advanced metering infrastructure data, it is now possible to be highly specific on a locational basis when evaluating historical load curves. Actual data is available from the secondary distribution circuits incorporating voltage and other factors. Also, there is now the opportunity to incorporate outside data sources, such as weather, for direct correlation. Having this data in hand is an extraordinary benefit to understanding the historical performance of the distribution system, and it also provides a foundation for more accurate forecasting and planning.

Probabilistic Forecasting and Intelligent Automated Analysis
Probabilistic forecasting is how ADP utilizes massive amounts of data to explore a wide array of potential futures, incorporate influencing factors, and understand the most likely scenarios where action may be required for remediation of issues. Utilities have relied successfully on human analysis to address system planning and forecasts typically based on limited number of single peak-hour, worst-case scenarios. Determining locational value, as well as evaluating the vast amount of data from daily or hourly scenarios creates challenges for traditional planning methodologies that can in some cases extend beyond the capabilities of manual analytical capabilities and new methodology is required using machine learning (ML) and artificial intelligence (AI).

Traditional distribution planning used trended historical loads at the feeder-level, with trends for peak load growth applied with local planner knowledge of specific distribution feeder history, and what each feeder's likelihood for growth should be. One of the most important aspects of the new requirements upon distribution load forecasting from distributed resources is that they be more granular at a hyper-local, geographical level. Spatial electric load forecasting is a method that is gaining acceptance and is used in order to better understand the distribution system at the feeder-level and downstream with small-area forecast down to all individual nodes across the distribution system. New spatial load forecasting that goes beyond the feeder level as a more bottom-up approach from contributions to future load from small areas is used in ADP. By using machine-based, probabilistic forecasting, ADP can address a vast number of potential scenarios to understand what the most likely outcomes will be and how to best address identified needs.

An important consideration in distribution planning is the interdependency between locational scenarios, which can influence outcomes. These complexities multiply the factors that must be taken into account in the probabilistic analysis. In addition, contingency margins can be narrowed for a more targeted investment on a locational basis rather than relying on unnecessarily wide gold-plated margins applied across the entire system. As shown in Table 2, the complexity of locational, scenario-based planning quickly outstrips human capacities and is best served using a machine-based methodology.

Table 2. Scale of Data Processing for Traditional and Probabilistic Distribution Planning Approaches

Planning	Traditional Approach	Probabilistic Approach	How to Succeed
Planning Fidelity	Peak/min-hour	8,760	Data reduction of similar-load hours
Circuits	100	100	Pre-screening of circuits
Years	10	10	Necessary for planning horizon
Forecasts	1	10	Necessary to define variance
Loadflows	2*100*10*1=200	8760*100*10*10=87.6M	AI- and ML-based approaches
Solution Matching	Wire solutions	Wires and NWA	AI- and ML-based approaches
Order of Operations	Human decipherable	N^(n-1) if unconstrained	Data reduction of irrational results

As shown in Table 2, an important component of ADP is the ability to perform data reduction. As shown in Figure 3, ADP reduces the data, provided the geographic location, and presented charts for the location based on data reduction using a maximum daily profile for a given month taken from load forecasts selected based upon predetermined confidence factors set in ADP by the regional distribution planner. Any element along the distribution line could be chosen by the distribution planner to create a chart, but using AI and machine learning methods, ADP checks each element along the distribution line for compliance with planning criteria, and matches best-fit solutions for the distribution planner to consider. A planner can then adjust criteria or input additional local knowledge for the ADP algorithms to consider and narrow potential solution options.

Given time-series analyses such as in the example in Figure 3, machine learning can reduce the number of scenarios and instances wherein an NWA solution may provide a better solution or where the wires solution may be marginal or not necessary at all. In this example, a traditional planning approach would have prescribed a wires alternative as data was not available to the planner and a deeper understanding of the duration and frequency of the planning criteria violation was known, but lacked context of the frequency and duration of violations throughout a forecast year.

Based on forecasts and modeling, the line segment example in Figure 3 exceeds planning criteria for loading in amps. A traditional response to this situation of exceeding planning criteria threshold for loading is to create a capital project despite its low frequency. From time-series analyses, ADP tells us exactly where the problem is; when the load is over planning criteria thresholds; and how much, how often, and how long the load would need to be reduced or a capital project planned to address the issue. ADP can also recommend an optimal NWA to solve, at a cost potentially below the capital investment required from a traditional wires solution, or if a solution is necessary at all for the situation.

In this particular instance there is also a considerable voltage problem, with no local feeder ties to transfer load. A feeder tie is not practical, nor is a new transmission source. To alleviate the planning criteria violations, ADP recommends two primary alternatives with the first alternative consisting of a combination of phase balancing and upsizing all the conductor on the main-line, and the second alternative consisting of phase balancing and microgeneration. In the example from Figure 3, ADP considered the additional benefit from improving poor reliability on the feeder that the wires alternative of upsizing conductor did not address.

Figure 3. Distribution Line Loading Percentage and Voltage Time-Series Example

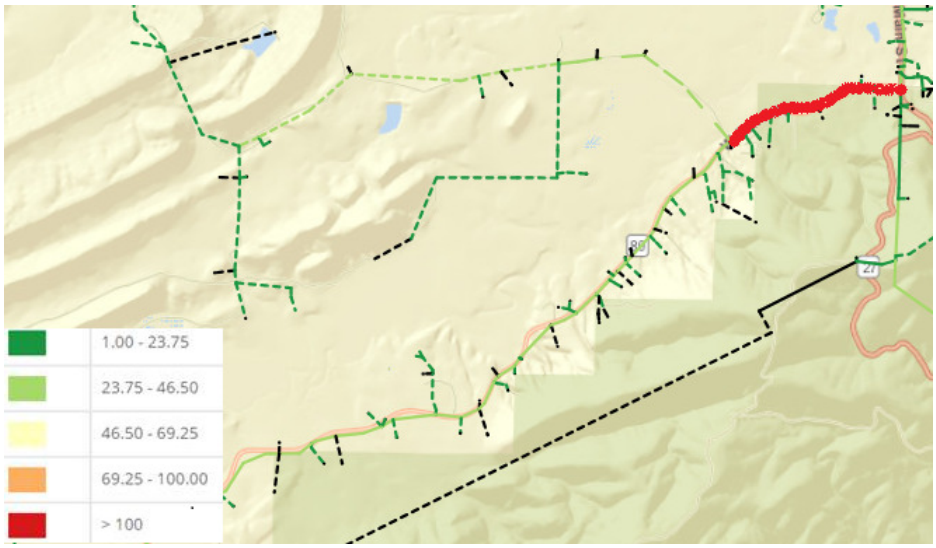
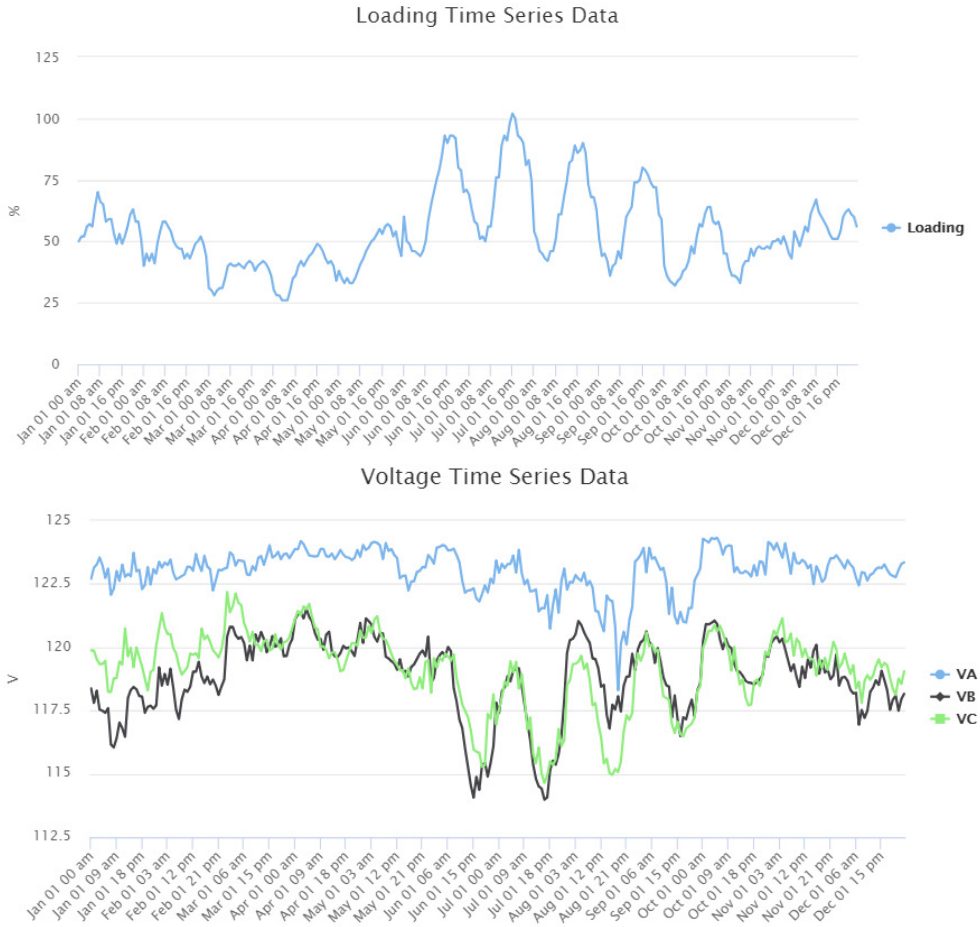


Figure 3. Distribution Line Loading Percentage and Voltage Time-Series Example (cont.)



Economic Simulation

By incorporating economic analysis and solution-fitting tools, ADP provides a method to identify the no-regrets investments for the utility. ADP provides a stored catalog repository of potential solutions to distribution system planning deficiencies and the machine learning capability to select the correct and optimal solution or combination of solutions that are tailored to the specific local distribution planning deficiency. The economics analysis of new NWA generation resources was once a major unknown variable for distribution planners, but recent research from CIGRE, US EIA, NREL and others have been published giving much needed insight into the levelized cost of new generation resources that can be used in the context of ADP for economic optimization of planning solutions[7, 8]. Once deficiencies and their possible resolutions are discovered, they can be aggregated to a system level. Typically certain types of deficiencies will emerge as common issues that need to be resolved, and certain resolutions will deliver the widest value. The utility can identify which decisions will resolve the maximum area under the curve for the lowest marginal cost. Issues that remain can be investigated for operational or other mitigation. ADP is designed to account for traditional, wires-based solutions and will help to optimize capital spending on physical infrastructure. ADP also accounts for non-wires alternatives with the intention of offsetting or deferring capital spending. Part of the no-regrets assessment is determining if programmatic changes such as demand response, rates, energy efficiency, or other alternatives might better serve a particular set of locational requirements. By incorporating non-technical factors and data in the economic analysis, ADP can assist utilities in understanding the best mix of solution alternatives and make investments that will meet payoff requirements in the time available.

Conclusion: ADP is a Future We Need Sooner than Later

Utilities have a challenging business climate ahead, and distribution planning will have changes required to meet the new challenges. Competition to utilities for energy supply is a growing force as microgrids and distributed generation, backed by storage, becomes increasingly cost effective. These approaches are being pushed by new market entrants who think they can separate the major commercial and industrial customers from the utility – accelerating utility revenue declines. In addition to the risk of revenue decline, utilities are facing the risk of capital cost acceleration resulting from a future that is increasingly ambiguous and difficult to plan for with long-term investments. Declining revenues and growing costs create an unsustainable business environment; this is the existential crisis the utility industry faces.

ADP should become part of a strategic response to this crisis. Applied thoughtfully and proactively, ADP can help:

- **Deliver no-regrets investments.** ADP will help optimize utilities' capital spend to its maximum impact and minimum risk. Utility customers expect this, and regulators will eventually demand evidence of this. ADP helps utilities separate investments based on risk (impact and probability) and have the data and evidence to communicate that rationale beyond peak-hour planning and worst-case forecasts. It also helps identify what challenges are better managed through non-wires alternatives or risk acceptance – a strategy already employed today.
- **Identify new types of customers.** ADP will allow utilities to identify how their customers are stratifying in expectations and requirements. Utilities are seeing increasing evidence that they need customized products as customer classes begin to value and demand different aspects of service (green, reliable, power quality, cost, digital services, etc.) differently. Competitive forces in the market see this stratification, and they are anticipating and preparing to compete for utility customers. Utilities must respond. ADP can help describe which customers require what services, allowing for targeted marketing and maximum-value customer engagement.
- **Focus on and leverage locational value.** ADP will also allow utilities to match DER services to customers with the optimum value proposition. Because ADP can identify wires investments and non-wires alternatives, the deferred cost component of the equation can become very specific. ADP tells which parcels of land and what points of interconnect can benefit from what load shapes, durations, and technologies. Since ADP can clarify "where", "what", "why", and "how much", the basis of DER service business cases are defined. This allows utilities to identify new revenue stream services and prioritize them based on clear opportunities, return, and scale. The result is better use of capital and the transition from lower regulated rates of return to higher unregulated rates of return.

Ultimately, ADP is a risk management strategy for utilities and their stakeholders. As the famous quote by Jack Welch goes, "When the rate of change inside an institution becomes slower than the rate of change outside, the end is in sight." That is a risk that the pace of change is bringing the utility industry today. Risk management philosophy says that as the probability of high impact risks grow, so must the mitigation strategy. ADP represents a rational response to managing the increasing probability of revenue and cost challenges, and ultimately, utility relevance. Change seen in other industries was not always managed proactively, but was foreseeable in retrospect. Utilities can see a future full of risk. The risk of embracing new paths will soon pale in comparison to the risk of ignoring it.

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