Long-Term Security-Constrained Optimum Dispatch Systems

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1. Introduction

I've visited this topic before, albeit in the 2018 post summarized and linked below.

SCADA – Part 6, Transmission and Distribution Network Management: *Generation and transmission management systems are commonly called "energy management systems (EMS). Distribution network management systems are mostly called distribution management systems or DMS. An EMS has several functions for medium-to-large utilities (which includes independent system operators (ISOs) and regional transmission organizations (RTOs)).*

Both load forecast and renewable production forecasts are important elements of demand and supply, especially as renewables continue to expand and become a major component of generation.

The starting point for modeling the grid is defining what generators are required to service the forecast load. Although the generation mixture changes day-to-day in response to changing load and generation availability, in the long term it is pretty consistent. Thus, only a small percentage of energy for the next few days need to be updated daily.

The first step in creating the model is to create a straw-man generation dispatch schedule that is optimized for least-cost and other constraints. The application that performs this optimization is often called a unit commitment program.

An automatic generation control application-set controls all dispatchable generation.

https://energycentral.com/c/pip/scada-%E2%80%93-part-6-transmission-and-distribution-network-management

Although the above 2018 post is still basically correct, the electric grid, its generation control methods and consumers have changed massively since then, and the pace of that change is accelerating. Thus, I thought it was time to update this general subject.

The title of this post comes from a new generation of grid-control systems that optimize how power-flow (dispatch) is controlled to improve efficiency, resilience and reliability.

2. Long-Term Modeling

In recent years, there has been relatively modest growth in electricity demand. However, the scale and pattern of electricity demand could change dramatically because of electrification of energy-demand currently met by fossil fuels, including space and water heating and vehicles. This electrification is likely to happen even more rapidly with incentives under the Inflation Reduction Act that are designed to accelerate and expand electrification. Figure 1 presents an example of a projection of potential growth in the coming decades, showing potentially dramatic growth.[1]

[1] Wesley Cole, Caitlin Murphy, Luke Lavin, and Evan Savage, National Renewable Energy Laboratory, "Understanding Power System Model Results for Long-Term Resource Plans," April 2024, https://www.nrel.gov/docs/fy24osti/88337.pdf

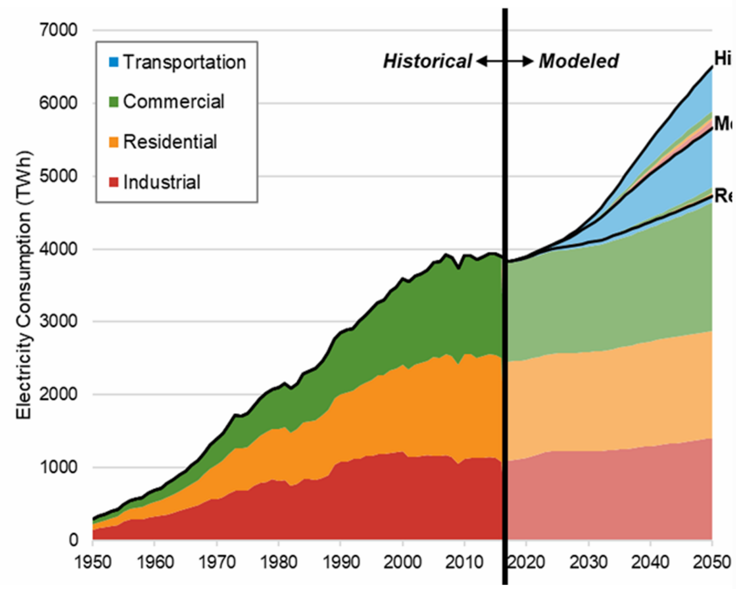

Figure 1. National demand for electricity from various sectors,
three projections for future load growth based on expectation
electrification of end uses such as transportation and heating.
Source: Mai et al., https://www.nrel.gov/docs/fy18osti/71500.pdf

Electricity demand varies significantly over the course of the day and across the year, which means utilities must estimate not only the total increase in annual load but also when this additional load will occur. Electricity demand typically reaches its peak during summer afternoons, but this could shift to winter evenings-to-mornings if there is large-scale adoption of electric heating. This could create additional challenges in meeting peak demand, such as the limited ability of solar energy to provide energy during peak demand periods in the winter. There are also considerable uncertainties in predicting when shifts in electricity demand might occur based on consumer behavior and adoption of new technologies such as electric vehicles and heat pumps.

Best practices for estimating future growth in electric demand involves estimating the growth in electric load, the timing of when the load might come online, and the shape of the load. Creating these estimates can include performing bottom-up load modeling that includes the relevant utility service territory details related to service demand requirements and end-use equipment stock such as electric vehicles or building heating equipment type. Service demand requirements are dictated by local weather patterns, the makeup and efficiency of the existing building stock, temperatures set by customers on thermostats and water heaters, and the efficiency of the adopted equipment. If the utility has data or information about its customers' adoption trends, they can use those to make more robust predictions about how much electricity might be used.

The level of detail captured in the analysis of the evolution of electricity demand depends in part on how big the potential change might be. The most important aspect for resource planning is that these issues have been considered and that a deliberate and reasonable decision is made for how they should be captured in the resource planning exercise.

2.1. Demand-Side Resources

Demand-side resources in an integrated resource plan (IRP) can include any technology or intervention that modifies the load shape or annual electricity consumption. Examples are shown in Table 1. The table includes two types of examples for each category. The first is "prespecified," which means the resource is specified outside of the model that is doing the resource planning. For example, distributed photovoltaics (PV) adoption might be represented using a fixed growth trajectory. The second type is "selected by the model," which means the model decides to invest in or adopt that resource. For example, distributed PV might be selected by the model based on the cost or anticipated customer bill savings. You may also hear the terminology "exogenous" and "endogenous" in place of "prespecified" and "selected by or within the model."

Table 1: Categories and Descriptions of Demand-Side Resources Included in Some Power Systems Planning Models

Category	Description	Prespecified	Selected by Model
Distributed Generation	Customer-sited generation and storage resources	Adoption trend based on history or targets; used to modify load	Iterate with additional model of distributed generation adoption or include directly as a resource option
Energy Efficiency	Providing the same energy service with reduced consumption	Percent magnitude reduction and shape based on history or program targets	Resource options in the model that can be selected if cost-effective
Demand Response	Reducing energy consumption at times of system stress	Reduction in peak load or load during defined event based on program targets	Resource options in the model that can be dispatched at a specified cost
Demand Flexibility	Shifting energy consumption in time or space without reducing total consumption	Load modification based on history or assumed program targets	Resource options in the model that can be dispatched at a specified cost
Pricing	Provide customers with prices that more closely follow the actual cost of electricity production	Modify load based on assumed response to prices	Capture elasticities of end-use demand

Note: "Prespecifed" indicates a way to capture that category in a model without the model needing to represent the technology explicitly (exogenous representation); "Selected by Model" indicates the category is explicitly represented as a choice in the model and the model can choose to select it (endogenous representation).

These demand-side resources are often more challenging to include in resource planning efforts because they can be difficult to characterize (e.g., how will better insulation impact electricity demand given the wide range of buildings in the service territory?) and because their procurement can be difficult to specify (e.g., how much does it cost to reduce peak demand by 1 MW?).

Some of the categories in Table 1 are included more often in utility planning. Distributed generation, energy efficiency, and demand response have been part of utility planning to varying degrees for decades. Both distributed generation and energy efficiency share a similar challenge: They tend to be small, heterogenous resources that must be rolled up to something that can be meaningfully represented in a long-term planning model. Customer decisions to adopt behind-the-meter solar or batteries depend on compensation mechanisms (e.g., net energy metering, rebates, or tax credits), value of backup power, and societal factors such as whether their neighbors have solar.

Except through providing incentives for particular technologies, these demand-side resources are largely outside the control of the system planner. A common approach in planning is to pair planning models with estimates of energy efficiency and distributed generation adoption and performance, then incorporate those estimates as scenarios. That can be done iteratively to make selection of these resources endogenous or as a single passthrough of exogenous data…

2.2. External Factors

I have previously been involved in regulatory processes in California, and understand how dynamic this can be. One reason for this is that California has a very complex political environment, and any major external or internal change to the utility environment can trigger major disruptions to that environment. An example of this is seen by what happened during California's attempt to deregulate electric and gas utilities.

With the passage of AB 1890 in 1996, California led the nation in efforts to deregulate the electricity sector. The act was hailed as a historic reform that would reward consumers with lower prices, reinvigorate California's then-flagging economy, and provide a model for other states. Six years later, the reforms lay in ruins, overwhelmed by electricity shortages and skyrocketing prices for wholesale power. The utilities were pushed to the brink of insolvency and are only slowly regaining their financial footing. The state became the buyer of last resort, draining the general fund and committing itself to spending $42 billion more on long-term power deals that stretch over the next ten years. The main institutions of the competitive market established by AB 1890, the Power Exchange and retail choice in particular, have been dismantled. The debate over the exact causes of the crisis continues. Many wish to distill the genesis of the crisis to simple themes. Some, most notably major political actors in California, lay principal blame on market manipulation by the merchant generators. Others, including the Federal Energy Regulatory Commission and energy firms, point to flaws in the state's restructuring plan and a fundamental supply and demand imbalance. Any search for simple answers, however, risks misperceiving the intricacies of the systemic failure of California's electricity sector. A satisfactory explanation for the severity of the crisis and its consequences cannot be composed based on any single factor. Rather, a number of factors must be considered. These include:[2]

- *A shortage of generating capacity,*
- *Bottlenecks in related markets,*
- *Wholesale generator market power,*
- *Regulatory missteps, and*
- *Faulty market design*

The 2000 and 2001 market failure (a.k.a. "The Meltdown") resulted in major pain for all involved. Considering the disruptions we are facing today (see below), everyone in our state's utility culture is very concerned.

Also, in the two decades between 1999 and 2018, California had a major series and droughts and major wildfires:

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[2] Christopher Weare, Public Policy Institute of California, "The California Electricity Crisis: Causes and Policy Options," 2003, https://www.ppic.org/wp-content/uploads/content/pubs/report/R_103CWR.pdf

- From 1999 through 2008 we had almost 3,000 wildfires that burned almost 7-million acres.
- From 2009 through 2018 we had over 3,000 wildfires that burned over 7-million acres.

Many of the wildfires in Northern California were sparked by the PG&E Grid, PG&E went through bankruptcy and restructuring in 2019, primarily due to their liability for the fires their grid sparked.[3]

Post-bankruptcy, PG&E has embarked on a major effort to underground their grid in areas prone to wildfires. The cost of this effort has resulted in their rates sky-rocketing. This has, in-turn, resulted in many of their residential and C&I customers installing photovoltaic (PV) systems.

PG&E (and other major investor-owned utilities in California) were able to get the PUC to greatly reduce the payments to consumers for power that was pushed onto the grid via net-energy metering going forward, which has encouraged consumers installing PV Systems to also install battery energy storage systems (which your author has done). However, the rapidly rising PG&E rates coupled with declining costs for PV and storage will encourage more consumers to install PV + Storage, reducing PG&E's revenue going forward. This will force our PUC to grant PG&E additional rate-increases in order to have it remain viable, encouraging additional consumers to add PV + Storage, etc., etc., etc.

3. Long-Term and Short-Term Challenges

Two major challenges that electric utilities and the large electric utility collectives (think Independent System Operators, Regional Transmission Operators and similar organizations) face is (1) the ability to accurately model short-to-medium-term (weekly and longer) changes in demand and (2) the ability to model these same changes in demand over multi-year periods as driven by climate change.

The good news is that the computer industry is developing more powerful tools that will, ultimately, be able to take on these challenges. The two earlier posts summarized and linked below, describe the challenges and potential future solutions.

Climate Complexity: *I was recently reminded that all activities of humanity, which impact all areas of science, are much more complex than scientists have learned to deal with. Shortly thereafter I read an article that was within one of the areas that I write about: climate change (a.k.a. global warming), and sure enough, the same story.*

"For the past year, alarm bells have been going off in climate science: Last year's average global temperature was so high, shooting up nearly 0.3°C above the previous year to set a new record, that human-driven global warming and natural short-term climate swings seemingly couldn't explain it. Now, a new series of studies suggests most of the 2023 jump can be explained instead by a familiar climate driver: the shifting waters of the tropical Pacific Ocean…"

https://energycentral.com/c/ec/climate-complexity

[3] See https://www.frontlinewildfire.com/wildfire-news-and-resources/california-wildfires-history-statistics/ and note that of the 20 most destructive fires in California's history six were caused by "Powerlines" or "Electrical system" in PG&E's Service Area. These include the Camp, Tubbs, Valley, Nuns, Dixie, and Butte Fires.

The Hardest Problems, Part 2: *I have been the electric utility branch of the computer industry for most of my career. During that time, I became well aware that, although there were many very large companies in this industry, there was really only one that was dominant: Big Blue. When I saw that they were getting into quantum computing in a big way, I knew that there would be a part 2 "The Hardest Problems" post.*

What, you don't know who Big Blue is? Read on.

Big Blue, a moniker that has resonated in the world of technology and business since the 1980s, is a nickname for the International Business Machines Corporation, better known as IBM. This nickname may have originated from the blue tint of its early computer displays or from the deep blue color of its corporate logo. However, Big Blue stands for more than just a color; it represents a tech giant with a rich history and far-reaching influence...

https://energycentral.com/c/iu/hardest-problems-part-2