Report 2.1: Price signals and demand-side management in the electric distribution and retail system

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Updated September 27, 2018

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Contents

1. Introduction

This report focuses on power distribution and retail — the 'last few miles' of electricity delivery — because this portion of the power grid in particular must be transformed if we are to decarbonize our energy system. Compared to transmission networks, today's distribution system is less sophisticated and less well monitored. However, it is the distribution system that will ultimately need to mediate the transition to a cleaner, decentralized energy future. Innovation towards a smarter and more flexible distribution system will thus be central to our efforts.

In a traditional power grid, supply flows from central generation radially outward towards spatially distributed loads. Supply can be controlled because it originates in coal, natural gas, and hydroelectric plants and the output can be adjusted by the plant operator. Loads are variable because the ISO cannot control when a customer turns on an air conditioner, flips a light switch or runs an industrial process and needs to ensure the requisite energy is supplied whenever these events happen.

In the future grid, power injection is expected to become both distributed and harder to control. Injection will be distributed because large power stations with generation capacity on the 100 MW or GW scale will be partially replaced by much smaller generation and storage resources. These will vary from kW scale solar home systems and car batteries, to small utility-scale wind and solar plants. Injection will be hard to control because wind and solar power are variable energy resources (VERs), meaning that their power output can rapidly change due to external factors such as random wind gusts and shading from clouds.

As there is effectively no storage installed on the grid from an overall energy balance perspective, [1] **it is imperative to find cost-effective ways of matching variable supply to variable demand. One set of ways to do this is to influence demand by incentivizing customers to shift loads to match generation.** In theory, a market in which price signals are passed to customers in real time would provide an economically efficient way to match supply and demand.

As discussed in Report 1.1, while wholesale markets in most regions are effectively free to find a price equilibrium, retail sales generally are not. This is due to both a social decision to protect customers from price swings, and to a technical inability to send price signals to retail customers based on their specific location in the distribution system. Realtime Supervisory Control And Data Acquisition (SCADA) systems are installed throughout modern transmission networks, measuring the power flowing through injection and withdrawal buses and through many transmission lines. Distribution networks, by contrast, have fewer real-time sensors installed per node. A traditional retail power meter, for instance, must be read by the utility each month either from a truck driven through the neighborhood using a short-range wireless signal or by physically reading the number off of a dial. The lack of real-time automated sensing makes it difficult to perform a state estimation of the network, which could inform the calculation of retail prices. Advanced Metering Infrastructure (AMI) to collect more distribution and retail system state information is increasingly being installed (see section 4.1), raising questions as to how it may be most effectively leveraged.

This report examines this state of affairs in the distribution and retail system, outlining the systems currently used for managing power and the feasibility of extending them to calculate distributional locational marginal prices (DLMPs). It also examines two existing methods for influencing load by incentivizing customers to adjust their behavior: demand response (DR) and time-of-use (TOU) retail pricing.

2. Managing power in the distribution system

2.1. Distribution feeder structure

Electricity is transported at high voltages (exceeding 69 kV) on the transmission system in order to minimize ohmic losses. In order to balance losses with safety, the distribution system lowers voltage in several steps corresponding to sections of the system.

The first of these steps is the transmission substation. These form end nodes in the transmission network, at which power flows out of the transmission system. Wholesale market LMPs, described in report 1.1, are thus calculated down to the substation resolution. [2, 43, 61, 93] Subtransmission lines operating at a lower voltage (roughly 34.5kV to 69 kV) will connect transmission substations to distribution substations, where its voltage will be stepped down again and its power will be fed into *feeders*, or distribution circuits. A diagram of a typical feeder is shown in figure 1.

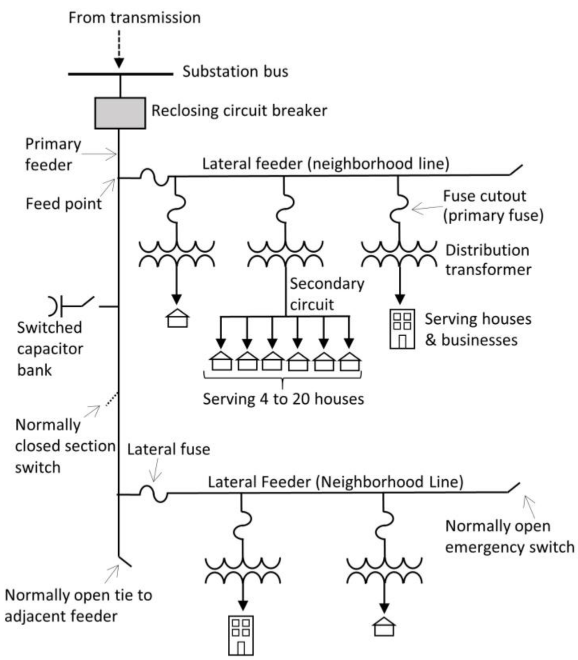


Figure 1: Typical structure of a North American distribution system feeder. Electricity flows from a substation along a primary feeder, to a lateral feeder. It is then stepped down further to a secondary circuit which branches to serve retail customers. From [92]. For comparisons between feeder designs in other countries, see Appendix A.1.

Each *primary* or *main line* is connected to the substation bus by a circuit breaker or fuse. This will shut power off to the entire feeder if a short is detected. A *recloser* is a fuse that will open when it detects a short, then briefly close again after waiting for a time period on the order of one second. If the system is no longer shorted (perhaps a tree branch or, as a PNNL report mentioned, a 'clumsy squirrel', caused the initial disruption and is now clear of the wires) the recloser will remain closed. If it continues to detect a short, it will stay in the open state and power to the entire feeder will be shut off.

Fuses are placed throughout the distribution system at the junctions between elements such as primary feeders, *lateral* (or *secondary*) feeders, and secondary circuits serving customers. They are also sometimes placed along main feeders and long laterals. Depending on the design and budget of a particular feeder, these may be substituted by circuit breakers or reclosers. **The hierarchical structure of feeders and breakers is designed so that shorts in one lateral or secondary circuit will isolate a contained section of the system without causing wider outages.** Furthermore, the normally open ties located at the end points of primaries and laterals allow them to be connected to adjacent circuits in order to improve reliability.

Topologies of these systems vary widely. For example, feeders may be designed in loops that normally operate independently but are connected in the case of a fault in one line. Radial feeders extending from a substation may be joined at end points, or may be joined in a 'spot network' involving a single bus at some point in the distribution system. Another variation involves redundant primaries built into a single 'dual source' feeder system.

In addition, the topologies of distribution systems vary based on the *secondary voltage* supplied to retail customers. This affects the design of the distribution system and its physical layout, as described in Appendix A.1

2.2. State estimation in the transmission system

State Estimation (SE) of the transmission system is a well-developed field. Its foundations were set by F C Schweppe in the late 1960s and 1970s [41, 69–71]. The basic basic problem of SE is to take many non-synchronized measurements of a system including both random and systematic errors, and find the actual state of the system as accurately as possible. We will briefly review SE in the transmission system here because it is far better developed than SE in the distribution system, and distribution system SE is largely an extension of it.

As described in report 1.1, the transmission system can be modeled as a number of buses (nodes in the system, for example, at generation facilities and substations) and branches connecting these buses. The state of this system at any one time is fully determined by the set of complex voltages at all buses and the network topology, including the impedance (ie. complex resistance) of each branch. It is the goal of SE to determine the system state based off of the available sensor data.

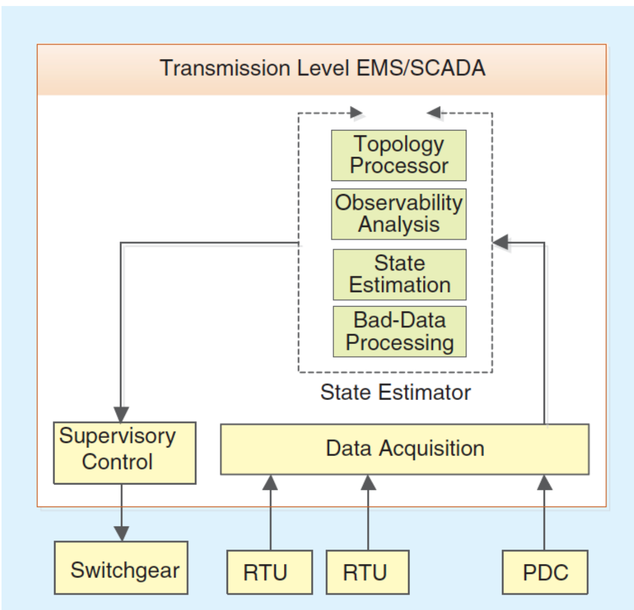


Figure 2: Architecture of an Energy Management System (EMS) used to monitor and control the transmission system. Data from sensors at buses is fed to the state estimator, which is run to calculate a snapshot of the grid state at a given point in time. This is fed to a supervisory control system, which is used to control switchgears (ie. circuit breakers and disconnect switches) in the transmission system. From [44]

Figure 2 shows the architecture of an energy management system used to monitor and control the state of a typical power grid at the transmission level. Each bus in the system is outfitted with sensors which feed into the data acquisition system. These are typically Remote Terminal Units (RTUs), Programmable Logic Circuits (PLCs) and increasingly Phasor Data Collectors (PDCs). These inputs are fed into the Supervisory Control And Data Acquisition (SCADA) system used to assemble an estimate of the system state and output control signals based on it.

The SE system typically receives enough measurements to over-specify the transmission system state. It first runs checks on the data coming in to identify and discard bad data (Bad-Data Processing) and to ensure that the remaining measurements are sufficient to uniquely specify the system state (Observability Analysis). It also combines known information about the transmission system such as the configuration of power lines with real-time data on circuit breaker configuration to determine the current system topology. All of these data are then used to perform a state estimation. Various algorithms can be used for this, with the most popular being a weighted least-squares (WLS) approach. [39, 95]

The Supervisory Control system may trigger actions based on the system state. For example, if a fault is detected the system may open a disconnect switch in order to isolate it.

The data entering the SCADA system has historically been taken at points with a time resolution of only two to four seconds, without precise synchronization between measurements at disparate buses [44]. The SE algorithm is typically run only every two minutes or so. Thus, the SCADA system can be relied upon for monitoring power injection and withdrawal in order to ensure that producers are complying with production targets and to schedule future dispatches but can't be relied upon to maintain system safety or power quality. System safety is derived from circuit breakers that respond automatically to shorts on sub-second time scales, and from the security constrained economic dispatch procedure outlined in report 1.1. In this dispatch procedure, the system state is re-calculated thousands of times with individual system components removed in order to determine whether the resulting state would violate capacity constraints. Dispatch orders are sent out accordingly, so that if any one transmission system component (such as a power line) fails the system will remain robust without any intervention from the SCADA system or from human operators.

The data available to SE systems is becoming richer with the widespread installation of Phasor Measurement Units (PMUs). These devices allow the measurement of voltage and current magnitude and phase angle, with synchronization between PMU measurements at multiple buses using GPS clocks. They are able to provide data points at a rate on the order of 100 Hz, about two orders of magnitude faster than traditional RTUs and crucially at a rate exceeding the 50-60 Hz frequency of the AC power being measured. Wide area measurement systems based on PMUs have been demonstrated since the late 1990s, capturing complex-valued power flows across large interconnections. [51,60,63] Such systems represent the ultimate in state estimation, but are currently limited by the sparse deployment of PMUs in most existing grids and by the processing requirements resulting from the volume of data generated by these devices. [75] It is envisioned that future transmission networks will deploy increasing numbers of PMUs in order to provide high-resolution SE over large areas. [55,84]

2.3. Towards state estimation in the distribution system

While SE is a crucial element of modern transmission networks, it has not been implemented in most distribution systems. Several factors explain this:

- **Functional differences:** Accurate power flow modeling is crucial to transmission networks because it is the basis for locational marginal prices. By contrast, the distribution system simply exists to handle flows in one direction with prices set months or years ahead of time. The engineering strategy was to build it to handle peak loads, pump power in, and otherwise leave it alone.

- **Node multiplicity:** Due to topological differences, SE is a harder problem in distribution networks than in transmission networks. A distribution system can have roughly four orders of magnitude more nodes than a transmission system in the same geographical area, which increases the capital and computational cost of SE.

- **Lack of redundancy:** Because of the radial topology of distribution networks, measurements at nodes are less redundant than they are in the typically more interconnected transmission networks. [90] This increases the difficulty of state estimation by making bad-data processing harder.

For these reasons, the distribution system is designed to be fully automated without passing much real-time data to central operators. As discussed in section 2.1, circuit breakers and reclosers are built into feeders in a hierarchical structure. These will automatically detect shorts and isolate sections of the grid when necessary. When this happens, the interruption will be detected by SCADA sensors at the substation and the utility will send line workers to the feeder to investigate and fix the problem. Human intervention is thus only required to repair equipment, to reset breakers once problems are fixed, for routine maintenance, and to read meters once a month for billing.

A major driving force for Smart Grid implementation is that automated distribution management increases grid resilience and reliability. A report from the US Smart Grid Investment Program measured the results of deploying sensors and feeder switches able to be monitored and controlled remotely. It found that these systems improved power reliability by rapidly allowing operators to isolate affected areas, improving the System Average Interruption Frequency Index by 17%-58%. [8]

However, the reliability benefits of distribution sensing and automation equipment will increase as the grid makes increasing use of zero-carbon distributed energy resources (DERs). As noted above, distribution grids currently conduct power in a radial flow and because of this they do not normally need to be reconfigured in order to ensure power quality. Injection and generation are kept in balance at each substation through industrious management of the transmission system, and as long as this is done diligently, distribution flows tend to be stable. (Some frequency and voltage regulation may be required, as shown in the capacitor bank in figure 1, but the power flows entailed are small.) In a distributed system with variable two-way power flows, by contrast, load balance and power quality will need to be continually maintained at every point in the grid. For example, batteries installed in the distribution system might be made to inject power to maintain load balance when a nearby load is switched on. Coordinating these resources in order to maintain a stable grid will require some degree of visibility into distribution system state that does not exist currently.

It should be noted that SE algorithms eventually used to coordinate the distribution system may not give a centralized snapshot of the entire system in the same way that SE in the transmission system does today. For example, distributed or hierarchical algorithms such as Multiarea State Estimation (MASE) may be used to reduce the computational burden on centralized infrastructure. Report 2.2 will include an overview of research in this area.

A second reason that SE will be desired in a future, decentralized power grid is that calculation of marginal prices at the distribution node level (ie. at individual buildings rather than at the transmission substation level only) and passing them on to customers is an economically efficient way of shifting energy consumption to better align with renewables generation, as discussed in section 4, below. The ability to pass such price signals on to consumers, relying on distribution-level SE, would thus obviate the need to install some energy storage or peaker plant capacity.

The ability to perform distribution level SE and use this to coordinate DERs is central to several roadmaps laid out for the future of the power grid. For example, the idea of a Distribution System Platform Provider, providing the services of a transmission Independent System Operator but at the distribution level, was introduced in New York's Reforming the Energy Vision (REV). [11,83] Numerous stakeholders agree that exposure to real-time data on DER state in order to actively manage the distribution system will be necessary for integrating DERs at scale. [12,49] An MIT Energy Initiative study emphasizes that "The economically ideal price... is embodied in the nodal or locational marginal price of electric energy at each point of connection and at each moment in time" [62] which would necessitate distribution level SE with high granularity.

Data inputs into distribution-level SE algorithms include the following:

- **Pseudo-Measurements:** based on historical load data, statistically likely loads for each customer at a given time point can be generated and used as inputs. Because this technique has the advantage of modeling every withdrawal node in the distribution network (though not very precisely), it is frequently used in distribution SE and load forecasting today. [57,58,91]

- **Substation bus SCADA** installed for state estimation in the transmission and subtransmission systems provides power injection information at each feeder

- **Microphasor Measurement Units (μPMUs)** are devices capable of measuring the relatively small voltages and phase shifts found in the distribution system. These have been tested in laboratory and demonstration projects but have largely not been deployed. [22,64,67]

- **Advanced metering infrastructure:** for example smart meters, given that the meters provide sufficient time resolution for the desired SE

- **Smart Switches:** devices like reclosers, circuit breakers, fault indicators, and other automated switches that provide one or two-way communications. Using these devices, the feeder can be not only monitored but remotely controlled.

- **Line sensors:** sensors which can be clamped onto power lines and used to inductively measure current. These do not provide as rich a dataset as μPMUs but are cheaper and simpler to install. They have been demonstrated in numerous labs and small-scale projects [40,88,94] and are commercially available. [9,30,52]

It should be noted that it has only recently become technically possible to provide a robust picture of the system at any give time with the rollout of smart meters, smart switches and line sensors in some distribution grids. While substations do supply a continuous stream of measurements, they only specify power injection into the feeder without adequate spatial resolution to determine what happens to that power along the feeder length. Smart meters providing datapoints hourly or more frequently are now deployed at more than half of US utility customer locations (see section 4.1). This datastream would not be sufficient for SE on a minute-to-minute basis, but in principle allows much more precise estimation than was previously possible. However, despite the availability of this datastream, most utilities that have installed smart meters use them for billing only and have not yet integrated them into full SE systems for distribution system management. [76]

2.4. (Advanced) Distribution management systems

Table 1 gives a summary of systems used to manage distribution networks. These were largely developed as separate, modular products by various services companies aimed at solving pain points for their distribution utility customers.

Most of the systems listed in table 1 are designed to react to outages or handle billing. The design principles followed are very different from those of the transmission system, which is built around the core goal of running a power market in which two-way flows must be reconfigured multiple times each hour to co-optimize physical and economic constraints. It is generally agreed that a future 'smart grid' will require the distribution system to become more like the transmission system, handling power flows in multiple directions and aiming to balance distributed, variable load with nearby distributed, variable generation. There is no consensus, however, on what management system design will facilitate this.

Advanced Distribution Management Systems (ADMS) aim to provide modular software packages to integrate the other systems listed on table 1, share information between them, and give the distribution utility a real-time view into the system state. For example, information from the SCADA system, smart meters, and FLISR may be fed into a state estimator. The output from the state estimator and geographic information system may be used by the outage management system to direct service crews in the field, all managed by the ADMS from a central location.

There is currently no standard set of ADMS capabilities, and different utilities have implemented systems with varying levels of integration. Typically they will issue a detailed Request for Proposals (RFP) and solicit bids to build a system that is highly customized to their needs. For example, Austin Energy's 2011 ADMS RFP was a 500 page document with 4,200 specific requirements. [59] Companies with experience building ADMS platforms include Schneider Electric, [29] General Electric, [28] etap, [33] Survalent, [82] and Siemens. [74] Once a contractor is selected and work begins, building the custom ADMS takes multiple years of collaboration between the utility and the contractor aimed at integrating the various systems and devices involved. [59]

There is a drive to develop and implement standards in all of these systems in order to enhance interoperability, make it easier for utilities to install ADMS, and to allow today's systems to flexibly accommodate increased DER penetration going forward. The Office of Electricity Delivery and Energy Reliability Advanced Grid Research Division launched a project in 2016 to develop an open source ADMS platform. [53] This project is currently being developed, and is scheduled to be completed in 2020. It aims to become the standard adopted by all ADMS vendors in the US by 2030. Other standards are also under development, such as the Multispeak Specification [5] which aims to develop common protocols for communication between distribution assets. These projects will be discussed in report 2.2.

Anther relatively new type of system listed in table 1 is the Distributed Energy Resource Management System (DERMS). These systems manage two-way communication with DERs in the field and interface with the distribution and transmission systems. It is envisioned, for example, that they will aggregate DERs in order to bid the resulting power into the transmission

Name	Abbreviation	Description
Used in both Distribution and Transmission Networks		
Energy Management System	EMS	Used to monitor generation, transmission and distribution assets and reconfigure them to improve performance. See figure 2
Supervisory Control and Data Acquisition system	SCADA	Sensors and software used for state estimation and control. See figure 2
Geographic Information System	GIS	Maps asset locations to enable planning and more efficient servicing
Distribution System Management and Optimization		
Fault Location Isolation and Service Restoration	FLISR	Sensors and automated switches integrated with state estimation and other systems, designed to isolate feeder areas where faults have occurred in order to minimize disruption to nearby customers
Outage Management System	OMS	Software built to determine the locations of faults, dispatch line workers for repairs, and estimate restoration times
Distributed Energy Resource Management System	DERMS	A software package used to monitor and control DERs and to interface between them and markets
Distribution State Estimation	Distribution SE	See sections 2.2 and 2.3.
Distribution System Operator	DSO	Proposed entity that would manage power flows and (potentially market or TOU based) pricing on a distribution system, analogous to an ISO for the Transmission System
Distribution System Platform	DSP	Proposed system in New York's REV plan allowing centralized management of a distribution system. See, for example, [83].
volt/VAR Optimization	-	Management of the voltage of power injected into a feeder and along its length, in order to reduce system losses while ensuring that the voltage along the entire feeder is maintained within required limits
Advanced Distribution Management System	ADMS	Typically modular platforms for integrating many of the distribution system functions currently handled by disparate systems (see text in section 2.4)
Customer Management in the Distribution System		
Automated Meter Reading	AMR	Meter design allowing personnel to drive by and take a reading based on a short-range wireless signal. Not a smart meter!
Advanced Metering Infrastructure	AMI	Networked systems broadcasting remote meter readings and allowing two-way communications between a grid connection point and a distribution utility, generally including 'smart meters' and communication infrastructure.
Meter Data Management System	MDMS	Software to store and analyze data from meter readings used for billing, state estimation, and long-term planning
Customer Information System	CIS	Relates customer personal information, usage history, and outage information to facilitate customer interactions

Table 1: A summary of legacy and emerging technologies for managing power distribution and retail systems. These were developed over decades as separate products to provide utilities with improved capability, and are integrated to a greater or lesser extent in different systems. The (Advanced) Distribution Management System (ADMS) provides a framework designed to integrate many of the subsystems listed into one complete whole.

system for sale on wholesale markets. California's Distributed Energy Resources Action plan lays the regulatory groundwork for such a system, [16] and FERC is actively working with stakeholders to develop rules for other jurisdictions. [48] Like ADMS, DERMS is a general term referring to systems with similar general goals and no agreed upon standard feature set exists. These systems share some features with aggregation systems built to manage demand response, which will be discussed in section 3.

3. Demand response (DR)

3.1. The potential for DR to lower peak loads

In a decentralized system with variable generation, one way to maintain energy balance is to adjust load according to the availability of power in the network. A mode by which this can be accomplished is to make flexible load respond to grid conditions by switching off during periods of high demand. Frequently the load will be switched on again during some other period, effectively shifting the demand from congested to non-congested hours. For example, a smart thermostat can be set to pre-ccol a home before warm hours, shifting load from hot afternoons when the grid is stressed to cooler mornings when it is not. **This 'Demand Response' (DR) strategy is an established business with experience aggregating distributed energy resources and both selling them to distribution utilities and bidding them as capacity into wholesale markets.** The goal is primarily to reduce demand during peak hours, when wholesale prices are high. The need for this is demonstrated in figure 3, which shows the relative frequency of locational marginal prices (LMPs) in the ERCOT system in 2015. As shown, LMPs were almost always below $40/MWh at all nodes in the system. During the most expensive hours, however, prices increased by more than an order of magnitude (and two orders of magnitude at the tail end of the distribution).

High peak prices like those seen in figure 3 are caused by high levels of system demand, such as that experienced on warm afternoons when many air conditioners are being run simultaneously. This can drive up all three components of the LMP (as discussed in report 1.1). Due to the absolute amount of load, expensive generators will be recruited and the marginal generator may be priced well above the usual cost of power, which increases lambda. The loss and congestion components increase because a high fraction of the generation capacity on the grid must be turned on in order to simply supply enough power, leaving fewer degrees of freedom than usual during security constrained economic dispatch optimization.

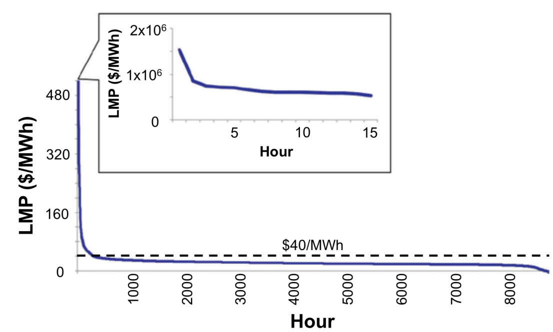


Figure 3: Locational Marginal Prices (LMPs) in the ERCOT system, showing price (vertical axis) against frequency with which that price was charged (horizontal axis). LMPs were typically under $40/MWh, while pricing during peak hours can be orders of magnitude higher. Data are from all of 2015. From [62], page 88.

A LMP price distribution similar to that shown in figure 3 is common in other systems as well, and has effects that are disproportionate to the relatively small fraction of peak hours. The first effect is that a large fraction of distribution utility costs are spent on procuring power during these time periods. For example, just 1% of electricity sold in MA during 2013-2015 accounted for 8% of total sales cost [45] and similar ratios are frequently seen in other systems. [31] **These large variations in wholesale rates are a major financial**

problem for retail utilities who are contractually obligated to purchase power at the wholesale LMP and sell it at time-invariant retail rates. By lowering peak LMPs, DR can therefore in principle significantly improve the profitability of utilities.

The second disproportionate effect of peak demand is that it determines reserve, transmission and distribution capacity.* Power infrastructure investments are based on peak demand, [86] and therefore lowering peak demand would lower the costs of transmission and distribution infrastructure as well as lower required investment going forward. Reserve capacity markets compensate generation assets to stay available without expecting to be used, so that their services may be purchased in the event of high demand. Because DR (and other strategies such as TOU rates) is able to lower peak demand, it is expected have a direct effect on these costs. [73]

Many studies have addressed the potential of DR to stabilize power markets going forward. A bottom-up study using smart meter data concluded that inexpensive (under \$200/kW levelized over one year) dispatchable DR in California could reasonably grow to 4GW by 2025, supplying 10% of projected peak load with only mildly optimistic assumptions. (More aggressive assumptions lead to 8 GW available at \$200/kWh, with dramatically more DR capacity available at higher prices.) [3,4] A study on industrial DR in Europe on theoretical (rather than likely) DR in the industrial sector found that it could reduce load by up to 93 GW, or 14% of peak demand during the study's 2010 base year. [38] Studies on the theoretical potential of specific technologies to perform DR have been done as well. It was found that air conditioners in California could provide up to 3.8 GW of curtailment [26], smart appliances such as dishwashers in a pilot in Belgium could reduce household peak demand by 65 W (on the order of several percent), [27] and electric water heaters could reduce overall peak demand in Norway by up to 4.2%. [68] Overall, DR can have a meaningful effect on system-wide peak load but potential contributions are heterogeneous with respect to customer segments and devices.

Appendix A.2 gives data showing that enrollment in DR programs in the US as a whole is currently just under 6% of peak power, and that this is in principle sufficient to have a significant effect on peak prices.

Logistically, DR providers maintain lists of participating customers with flexible load and the estimated amount of this load (measured in kW). During peak demand, the DR provider informs these customers and asks them to decrease demand. Should they choose to participate, for example by temporarily turning off an air conditioner or other flexible load, the DR aggregator is paid and in turn compensates the customer.

The DR provider can earn revenue through several different mechanisms. In the case that the DR service is run or commissioned by a retail utility (a 'Retail DR' program), the utility simply forgoes expenses by having to buy less power during peak hours. DR providers may also aggregate curtailment capacity and bid this into forward capacity or wholesale markets as though it were generation capacity. The legal ability to bid DR into wholesale markets is protected in the US by FERC Order 745, which states that DR must be compensated at the relevant LMP. [17] This decision was upheld in 2016 by the supreme court. It is generally acknowledged to suggest a legal framework for participation of other aggregated DERs in wholesale markets, which lead to it being a very controversial decision in the industry. [13, 56, 89]

Traditional DR services are a well-established industry, but tend to rely on older technology such as phone calls, emails and text messages to send curtailment signals. These have historically made DR cost effective only for medium to large customers (see section 3.2.) A range of newer systems using more sophisticated and automated strategies are being developed which will make coordination of smaller customers cost effective (see section 3.3). As these systems evolve to become more sophisticated and automated, DR could be extended to pass price signals into the distribution system with increasing spatial and temporal granularity.

*Reserve capacity is a separate market in many power systems. 'Transmission capacity' and 'distribution capacity' refer to the ratings of power lines and other infrastructure such as transformers, determining the fixed capital cost and affecting the maintenance costs of these systems.

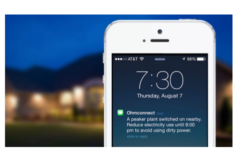
Enernoc (Owned by Enel)	ENERNOC	Enernoc is the world's largest provider of DR. They focus mainly on industrial and commercial customers, and operate in many markets worldwide. Their primary DR product includes hardware installed on site, and a software portal where facilities managers are able to respond to DR signals.
CPower		CPower also focuses on commercial and industrial customers, and combines user historical data with data from the distribution utility in order to provide facilities managers an integrated web portal. They also support automated DR, in which equipment can be automatically controlled according to DR signals.
Opower (Owned by Oracle)	OPOWER	Opower provides a customer engagement platform, with a residential portal that communicates incentives to get users to respond to DR signals and other nudges.
Tendril		Like Ohmconnect, Tendril provides a customer engagement platform for the retail utility. Their 'Orchestrated Energy' DMS gives utilities the ability to aggregate and control devices in real-time within user-set limits and grants access to data analytics that can be used for planning investments and promotions. Their residential customer platform provides increased access to personal data, notification of DR signals, automated DR support, and information about promotions.
Rush Hour Rewards (Nest/Alphabet)		Nest owners can register in a retail DR program, in which temperature will automatically be adjusted to pre-cool homes before warm periods and reduce AC use during hours of high demand. The program claims to automatically adjust the thermostat 6-12 times per season and save subscribers \$20-\$60/year. [42, 81]
Ohmconnect		Ohmconnect is a startup focusing on residential customers and bidding their DR resource into wholesale markets. They use primarily behavioral means, such as alerts to consumers when power is expensive, rather than automatic control of devices. [77]

Table 2: A small selection of DR aggregators. While many companies offer DR as a service, this list illustrates the breadth of their business models and technical capabilities. These companies vary based on the **types of DR resource** they offer such as industrial, commercial, and residential; the **purchaser of DR capacity** meaning whether it is sold to retail utilities or into wholesale or ancillary services markets; their **use of IoT devices** as opposed to traditional DR signals via text, email and phone call; and their **degree of distribution system integration** ranging from none to providing a proprietary DMS.

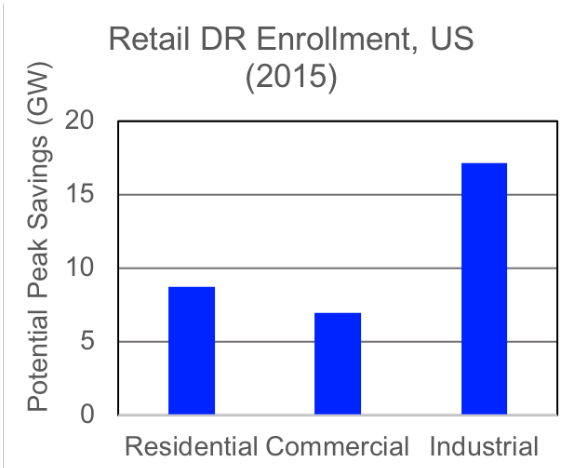


Figure 4: Capacity enrolled in Distribution DR programs in the US as of 2015. These programs are designed to relieve distribution utilities of the need to purchase power during peak hours. In line with historical breakdown by sector, the industrial sector supplies the most DR capacity. From [79], Table 3-1.

3.2. Large industrial DR customers

Historically, the majority of DR has come from large power consumers such as heavy industry. [10] A breakdown by sector in distribution DR program enrollment in the US is shown in figure 4, and reflects this historical tendency. Industrial customers are a natural target for DR programs because they are large consumers of electricity and are frequently able to reschedule tasks if doing so would lower their production cost.

One category of industrial DR customer participates in wholesale markets directly. These are typically very high volume electricity consumers such as aluminum producers. Some have special arrangements in which they are able to buy and sell power on wholesale markets without intermediaries, curtailing their production during hours when high prices make production of their product non-economical. [23] (page 3)

Another notable category of industrial customer with DR programs is the datacenter. As datacenters throughout the world use an increasing share of electricity produced, their effects on the grid become more profound. Fortunately, many tasks can be delayed when energy prices are high and performed when they are low. This has created a subfield of scheduling algorithms directly linking data management to scheduled energy use. [14, 54, 87]

3.3. DR aggregators and platforms

Many companies aggregate DR potential peak demand. These range from independent players who bid capacity into wholesale markets, to systems that essentially act as customer engagement platforms for utilities. Several of them are summarized in table 2. This is by no means a comprehensive list, but highlights some of the notable players and gives a sense of the range of services offered. It should also be noted that some of these platforms support some degree of distribution system SE, and many support TOU rate structures (discussed in the next section). As pricing becomes more granular in time and space, these three functions (SE, DR and TOU) are likely to become increasingly integrated.

4. Time of use (TOU) pricing

TOU pricing reflects a classical economic approach to electricity retail by which customers are passed pricing signals and are able to adjust their behavior based on them. As rational economic actors they can thus decide, as changing generation and load conditions affect prices, which of their devices is worth the marginal cost of power at this time increment. For an overview of rate structures that have been used and what has been learned about their effectiveness in altering customer energy use, see section 4.2 and Appendix A.4.

TOU and DR both fall under the umbrella 'demand-side management' and are similar in that they both involve influencing customer behavior via an economic signal. Definitions of TOU and DR vary throughout the literature, but tend to exhibit two main differences. Firstly, the type of economic signal varies. DR typically uses an on/off signal sent out at varying times in response to grid congestion. TOU pricing, by contrast, captures (usually prescheduled) time-dependent pricing tiers at a range of granularity. Secondly, **DR can be bid into wholesale markets as capacity, whereas TOU can not.** Therefore, the type of economic settlement and the way that power markets accommodate these two systems can differ substantially. It should be noted that the definition of DR has been stretched in the literature to include more granular services that overlap with what might traditionally be called TOU, such as "Shift DR" in [3].

TOU pricing brings with it clear benefits, barriers and concerns:

- **Economic benefits:** TOU implements classical economic principles in power markets. If people want energy during peak hours, they will theoretically be willing to pay for it. Classical economics would suggest that making them pay the full cost of electricity at their location at every point in time is the most economically efficient way to shift loads to off-peak hours. A study by LBNL, for example, found that the levelized cost of TOU programs is lower than that of the traditional DR solutions examined. [3]

- **Technical barriers:** For accurate real-time signaling, prices must be calculated at all distribution nodes in the system. If rates are instead determined based on projections, it is at least necessary to measure consumption at each node with the appropriate time resolution. See section 2.3 above.

- **Behavioral barriers:** it is a truism in the power industry that retail customers spend only ten minutes per year thinking about their electricity use. [20] This is why increasing 'customer engagement' is a major concern of distribution utilities. Realistically, customers will not be willing to put much effort into optimizing their energy use or be willing to forego electricity if it means giving up comfort or other benefits. Appliances will need to be automated in a way that takes into account user preferences and minimally interferes with functionality.

- **Social concerns:** Retail costs are intentionally averaged over time and location in today's system because we believe that everyone should have access to inexpensive energy. To the extent that price signals are increasingly sent to retail customers, this has the potential to be a regressive reform with the costs of stabilizing the grid disproportionately borne by those least able to pay. Market design will have to account for this and make sure that, for example, disadvantaged elderly people are able to afford air conditioning during a heat wave. These concerns might be dealt with by allowing prices to vary during the day only within a pre-set range, by using a finite number of pre-determined price levels, by making Off-Peak hours extremely cheap, or by using other schemes. See, the rate structures in Appendix A.4 for examples of tariffs that try to balance economic and social factors.

Because of the economic benefits of TOU rates, they are increasingly being implemented in power systems worldwide. They are available to at least some customers in fourty-nine US states [15] page 18, and are likely to have a significant role in the future power grid. As we develop decentralized tools for pricing and trading power, supplying TOU price signals and allowing tariff structures to be judiciously designed will be important elements of this work.

4.1. Smart meter penetration

Existing electric meters must be checked manually (traditional meters) or using short-range wireless (AMR), and are thus read approximately monthly. Smart meters are therefore crucial in order to measure consumption as a function of time in granular detail for the implementation of TOU rates.† It is projected that 53% of electricity and natural gas meters worldwide will be 'smart' by 2025 [66] with much of the growth in the short term occurring in China. [80]

†Smart meters enable DR as well, but because DR schemes tend to be simpler and tied to other electronic devices like thermostats, there exist more work-arounds than for TOU.

Like most aspects of the distribution system, the factors leading to smart meter installation are very region-specific. This is shown in the maps in Appendix A.3, which demonstrates that some areas in the US and Europe have (or will soon have) very high penetration while others have quite low levels. Smart meter roll-outs are unusual territory for distribution utilities. They are expensive in aggregate so must be considered an important part of cost estimations, and are also extremely consumer facing. This has lead to conundrums that utility companies are not used to, such as a texan woman threatening a smart meter installer with a gun [25] and a high-profile failed AMI roll-out in Colorado which angered residents. [46] People seem to be unusually suspicious that smart meters are either a plot to spy on them or a mechanism to raise their power bills. These seem unlikely to delay smart meter investments for long, however, as roll-outs have continued despite pockets of intense protest. More of a barrier are economic concerns as to the payback periods of the devices, as regulators in many jurisdictions must be convinced that new infrastructure is economically efficient. [78]

It should be noted that the smart meters being installed typically broadcast datapoints either hourly or every fifteen minutes. While this is sufficient for hourly TOU billing and some amount of SE, these meters do not provide enough information to run granular SE for other functions. As discussed in section 2.3, the time resolution required for different functions varies. Hourly resolution may be sufficient for billing and for directing repair crews to fix power lines, but not for managing load balance or grid safety. If in the future a distributed, continuous power market transacts continuously based on distribution-level LMPs and aims to perform automatic load-balancing, a timescale of minutes or seconds may be desired. This will likely require new hardware. **Because spending decisions are made on a piecemeal, regional basis, any successful trading protocol should be designed to be flexible. It must accommodate a wide range of measurement types and allow access to the broadest possible feature set given whatever inputs it has to work with.**

4.2. Tariff Structures

Tariffs may be structured with pricing tiers at varying time resolution. Most commonly, there will be an expensive peak hour rate and an inexpensive off-peak rate with prices and the peak hour schedule set beforehand. These rates may affect the energy portion of a customer's bills only (which accounts for roughly half of a typical retail customer's bill), or both the energy and the delivery fee.

Additional parameters that are often included are:

- **Critical peak pricing (CPP):** this adds an extra, pre-determined premium to rates during a limited number of peak hours per year
- **Variable peak pricing (VPP):** adds a variable premium to a pre-determined set of peak periods. The premium is calculated, for example, the night before and sent to customers.
- **Flexible Duration:** extends peak hours when demand is especially high
- **Partial Peak:** adds a third time period when prices are in-between peak and off-peak hours
- **Demand Charge:** provides an additional charge based on the 15-minute period during a billing cycle when the customer used the most power, typically found as part of commercial and industrial (rather than residential) rate structures. Demand charges can be significant portions (ie 50%) of the total power bill. This incentivizes smoother load profiles.

Appendix A.4 gives examples of some TOU tariff structures.

Numerous studies have examined the effects of TOU peak pricing schemes using data from real customers in the field. These studies give insight as to the response of customers to a given on-peak/off-peak price differential. It was found, for example, that commercial customers in CA effectively did not respond to a 28% differential, [47] while Canadian residential customers facing differences in excess of 200% (ie. tripling of prices during peak hours) lowered their peak consumption by 11%-20%. [85]

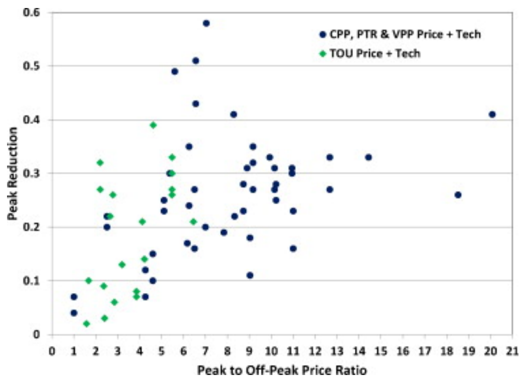


Figure 5: Results from a meta-analysis of 34 studies examining the effect of TOU rates, with price ratios on the horizontal axis and peak use reduction on the vertical axis. Adding additional peak charges such as CPP and VPP (blue dots) increased the median ratio between prices during peak hours to prices during off-peak hours, as compared to schemes with invariant TOU rate structures (green diamonds). This plot shows data from studies in which enabling technology was installed to communicate prices to consumers. In all groups examined, the meta-analysis found a correlation between Peak/Off-Peak Price ratio and Peak Reductions driven by consumer behavior. [36]

Data from one meta-analysis of 34 separate TOU studies is shown in figure 5. The researchers broke participants into groups based on whether a CPP or VPP component was included in the rate structure, and whether additional enabling technology (such as smart thermostats) was installed in order to make prices more salient to consumers. They then looked for correlations within these groups between pricing structures and peak reductions. They found a correlation between peak reduction and on-peak/off-peak price ratio in every group, suggesting TOU pricing schemes were effective in lowering peak energy use. This work highlights the importance of rate design in TOU pricing, and contributes to a body of evidence of its effectiveness. **In general, evidence shows that consumers react to TOU rates by lowering their peak consumption, as might be expected, as long as the ratio between on and off-peak rates is sufficiently high.** [34–36, 50, 65]

The TOU options discussed above give the distribution utility only limited ability to adjust prices as a function of time of day or location within the distribution system. A more economically efficient system might pass signals that are more granular in space, time, and price to reflect the actual production and consumption wherever and whenever a unit of electricity is being used. This is only starting to become possible with improved state estimation, and research in this direction should be expected in the coming years.

5. Evolving environment

There is a general consensus in the power industry that Distributed Energy Resources (DERs) are a crucial part of the future electrical system, and will play a vital role in its much-needed decarbonization. There is also general agreement that in order to deploy DERs in a cost-effective manner, price signals will have to be implemented with increased spatial and temporal granularity. Beyond this, there is little agreement as to what the tariff structure should look like or what technologies should be employed to enable it.

One major milestone in the transition towards a power system with increased DER reliance was FERC's Order 745, stating that DR aggregators must be able to bid power into wholesale markets and be compensated the avoided cost of producing power (see section 3). This established that DERs have a role to play in the bulk electric system despite the fact that their characteristics are so different from large power generation stations. Additionally, FERC Order 845 in April 2018 revised interconnection requirements in order to allow more straightforward grid interconnections for facilities incorporating storage capacity. [19] FERC is also actively soliciting stakeholder input on additional rules governing the role of DERs more generally in the power system. [18]

While pilot TOU and DR programs exist in many regions, they tend to be opt-in pilot programs. This is beginning to change. California's new Net Energy Me-

‡Net Metering refers to the practice of billing customers for the net amount of energy they use in a billing period, effectively allowing their meter to run backwards when they are producing energy. For example a home with solar may produce excess energy during the

tering rules, adopted in 2016, require any new customer applying for net metering[‡] to adopt a TOU rate. [6] **It is expected that as both the economics and technical implications of increasingly granular price signals are better understood, this will substantially transform the power system. The development of an open source energy trading framework stands to accelerate and enable this process by improving interoperability between legacy systems, affording participants technical control over the system, and allowing them better visibility into its behavior.**

day, crediting this against their energy use at night.

A. Appendices

A.1. Global differences in distribution system architecture

As shown in figure 9, distribution feeder designs of different countries vary. In North America, retail customers are typically delivered 120V power whereas in Europe the standard is 230V. Additionally, secondary circuits in the European system tend to be three-phase whereas those in North America tend to be single phase. Both the high voltage and three-phase design lead to lower attenuation in the secondary feeder cable. As a result, secondary circuits in the North American design can be only about 250 ft long whereas those following the European design can be about one mile. Therefore, while a single secondary circuit in North America will supply only a few buildings a single European circuit can supply many. These electrical design differences thus affect the topologies of distribution networks.

The practical design differences between these systems are primarily that the European system requires more expensive transformers at the interface between the main feeder and the secondary circuit, and is more flexible at the secondary level than the North American system. This flexibility (the ability to attach many buildings to the same secondary circuit) makes it generally a more cost effective system in urban areas. The North American system is better optimized for rural areas and there is some evidence that its more hierarchical structure (fewer buildings per secondary circuit) makes it more reliable on average. See [72] for additional details.

The 'North American' design is used in North and Central America, Brazil, and Japan. Most other countries use the 'European' design.

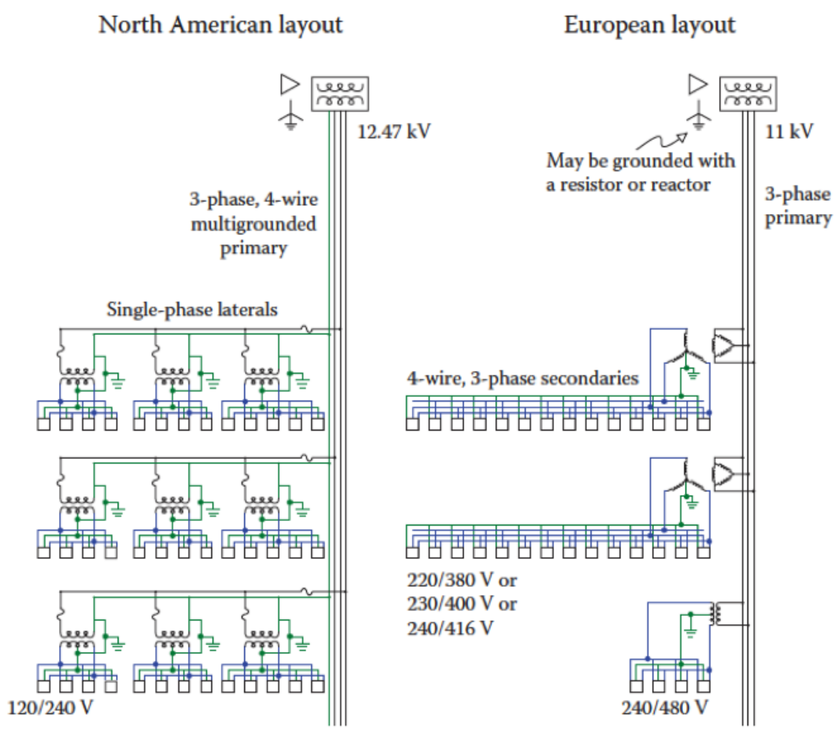


Figure 6: A comparison between a typical North American feeder design and a European design. The North American system is optimized to deliver 120V electricity, while the European design delivers 230V. From [72].

A.2. Enrollment in demand response and ability to lower peak prices

These data contextualize the amount of DR currently available and the effect that supply can have during periods of high demand. Table 3 gives a summary of DR enrollment in major ISOs in the United States. As shown, enrollment varies significantly based on regional incentive structures, but in general can provide a peak reduction on the order of a few percent. In order to contextualize the effect of DR on wholesale prices, Figure 7 gives the wholesale market price in ISO New England in July 2018. This shows that during periods of high demand, the market clearing price can jump substantially. Therefore, a reduction in peak demand of only a few percent can substantially lower market clearing costs and improve system stability when it is most needed.

RTO/ISO	**Potential Peak Reduction (MW)**	**Percent of Peak Demand**
California ISO	1,997	4.3%
Electric Reliability Council of Texas	2,253	2.9%
ISO New England	2,599	10%
Midcontinent Independent System Operator	10,721	8.9%
New York Independent System Operator	1,267	3.9%
PJM Interconnection	9,836	6.5%
Southwest Power Pool	0	0%
Total	**28,673**	**5.7%**

Table 3: Demand response capacity (ie. potential peak reduction) enrolled in the major US ISOs and RTOs in 2015. Percent of peak demand gives [potential peak reduction] divided by [average peak load] in the listed system. From [79]

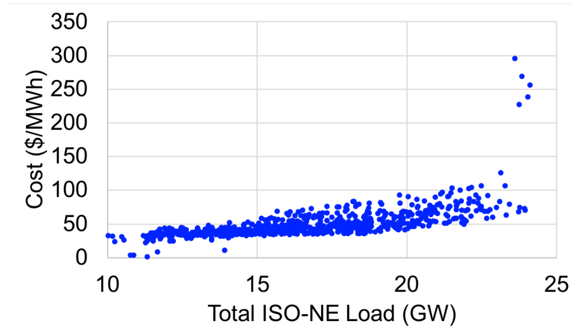


Figure 7: The ISO New England hub price, corresponding to a system-wide reference price in the real time hourly wholesale market for every hour in July 2018. As shown, peak prices vary stochastically based on the system state and the generation available but tend to exhibit a thresholding effect at peak hours. The result is that relatively small reductions in demand, such as those provided by DR, can greatly affect peak prices. From [32]. Note that DR programs are active in New England, and that these data implicitly account for them. This does not take away from the main purpose of the graph, which is to illustrate stochastic sudden increases in power price during peak hours.

A.3. Smart meter deployment by region

As discussed in section 4.1, regional policies and economics greatly affect the penetration of smart meters. Two maps below demonstrate this in Europe and the US.

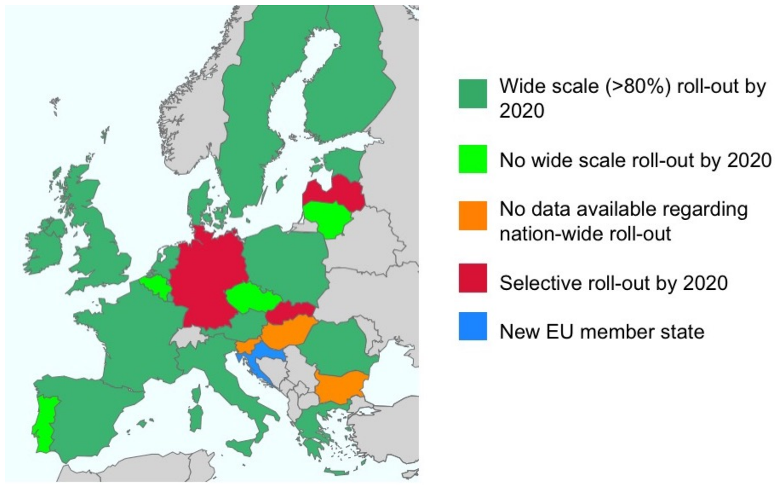


Figure 8: Targets for roll-out of smart meters in the EU. It is estimated that 72% of EU customers will have smart electric meters by 2020. Selective roll-out means that utilities will target smart meter installation based on some set of (usually economic) criteria. From [37]

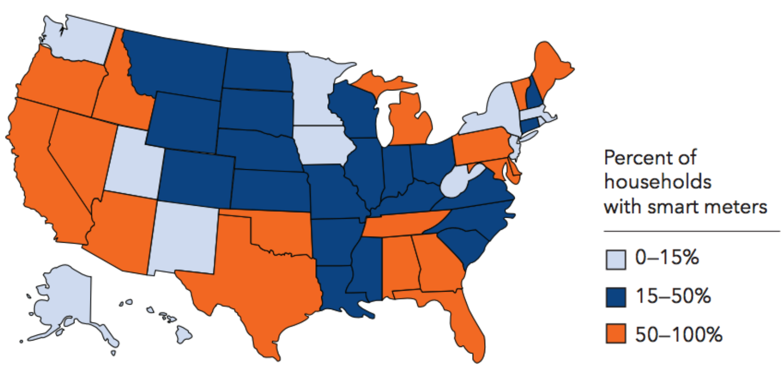


Figure 9: Prevalence of smart meters in the United States as of 2015. From [20].

A.4. Example TOU rate schedules

A longstanding TOU rate system is the 'Tempo' Tariff in France summarized in figure 10. This structure makes a concerted effort to balance economic incentives with social welfare. In this scheme, there are two rates every day: a high daytime rate and a low nighttime rate. Days are color coordinated based on projected electricity use during that day, and the utility chooses the color every night for the following day. Rules are set up restricting the number of expensive 'red' days per year and what days of the week are allowed to be red; for example, Sundays are always blue and red days cannot fall on week-ends or holidays. Electricity use is highest in France due to electric heating during cold months, so red days usually fall on the coldest days in winter.

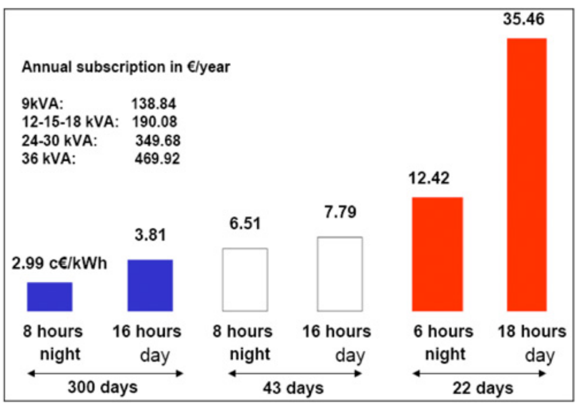


Figure 10: A summary of the Tempo Electricity Tariff in France. This combines peak and off-peak pricing with varying rates based on projected use during a given day. See the text for additional description. From [21].

ConEdison, a utility in New York, offers TOU schedules notable for aggressive disincentives to use electricity during summer days and nearly free energy supply year-round from baseload generation. Rates are shown in table 4. In addition to a specific response to DERs, this rate structure reflects a desire to generally increase load factor (average demand divided by peak demand). Load factors have been falling in the US since the 1970's largely to increased use of air conditioning and the broad transition from an industrial to a service economy. The decline in load factor is costly for the reasons discussed in section 3 (ie it represents an increase in peak demand).

Season	**Peak (Cents/kWh)**	**Off-Peak (Cents/kWh)**
Summer	29.38	1.08
Standard	14.47	1.08

Table 4: ConEd Business TOU rate structure. Summer is June 1 to September 30, and the rest of the year uses the 'standard' tariff. Peak hours are 8:00 to 22:00, and off-peak hours are 22:00 to 8:00. ConEd also offers TOU rates for residential customers and EV owners that are less aggressive, with summer Peak/Off-Peak ratios of 14 rather than 27. From [7]

Figure 11 shows the timing of peak and off-peak periods adopted by San Diego Gas & Electric in Southern CA as of late 2017. This new tariff structure is a direct response to increased solar penetration affecting energy prices. It moved peak periods later in the afternoon in order to create economic incentives to smooth out the infamous 'duck curve' which creates problems for utilities due to solar production falling in the early evening right as residential consumption is increasing.

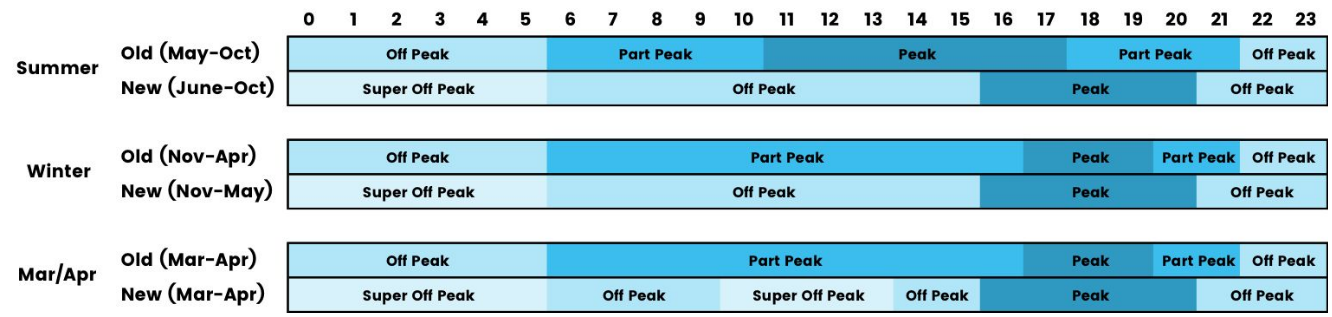


Figure 11: Comparison between old and new peak pricing hours adopted in December 2017 by San Diego Gas & Electric. Peak hours were shifted later in the day and a new 'Super Off Peak' time period was added. From [24].

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[1] There is 24.2 GW storage operational in the US, and simply multiplying each project's rated power by its duration gives a total capacity of 204 GWh (https://www.energystorageexchange.org/ accessed 8/20/2018); Total nameplate capacity of all generation is 1,177 GW and total generation was 3.8 PWh in 2016 (https://www.eia.gov/electricity/data.php accessed 8/20/2018). Thus, storage equates to 2% of installed generation capacity (ie. current) but only 0.005% of annual generation (ie. energy). Storage can thus play a significant factor in lowering peak demand in some areas, but not in time-shifting meaningful amounts of generation on the grid as a whole.

[2] In practice, LMPs may be calculated down to either nodal resolution (corresponding to generation capacity and substations) or to zonal resolution (corresponding to groups of nodes presumed to have low congestion within the zone). In some systems prices are calculated down to the nodal level and averaged in order to produce a zonal price, and this zonal price is used for market clearing. Market design varies between zonal, nodal and hybrid systems.

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