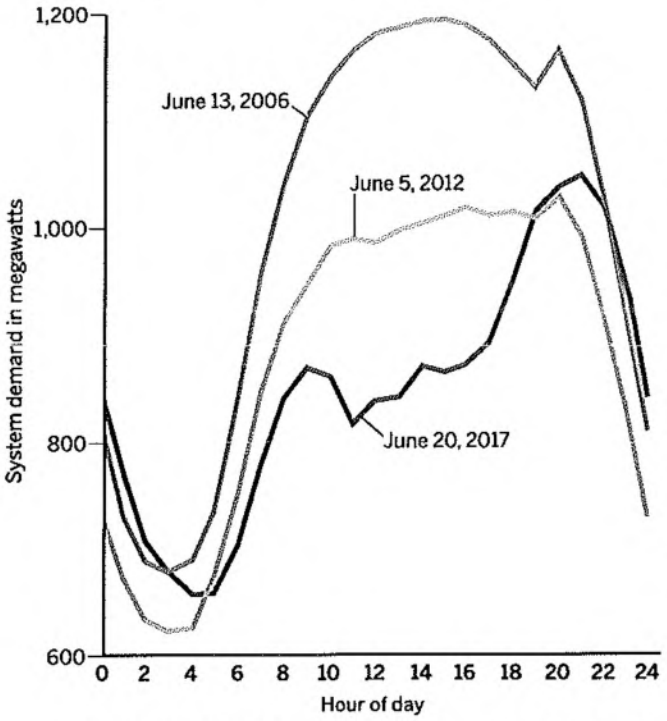
Figure 23. Evolution of system load in Hawaii on typical June weekday



Data source: Federal Energy Regulatory Commission. *Form No. 714 — Annual Balancing Authority Area and Planning Area Report*

The capacity role and treatment of variable renewable resources, such as wind and solar, vary among jurisdictions and RTOs. The cost of service study should reflect the role of these resources in supply planning, by classifying part of the renewable costs as demand-related and allocating those costs in proportion to class consumption in the hours contributing to capacity requirements. This should recognize that different types of variable renewable resources can be complementary in many respects as long as the temporal patterns, either daily or seasonal, are different. Even solar in slightly different regions can be complementary since they may not be affected in an identical way by cloud cover. For example, as shown in Figure 24 on the next page, a mix of wind resources from West and South Texas plus solar production combine to produce an overall resource shape that corresponds moderately well to the shape of the summer diurnal load (Slusarewicz and Cohan, 2018; Electric Reliability Council of Texas, 2019).

The costs of these resources can be assigned to the hours in which they generate energy, as discussed in Chapter 17. Determining the hours that variable resources provide energy (on either a historical or normalized forecast basis) is generally straightforward.

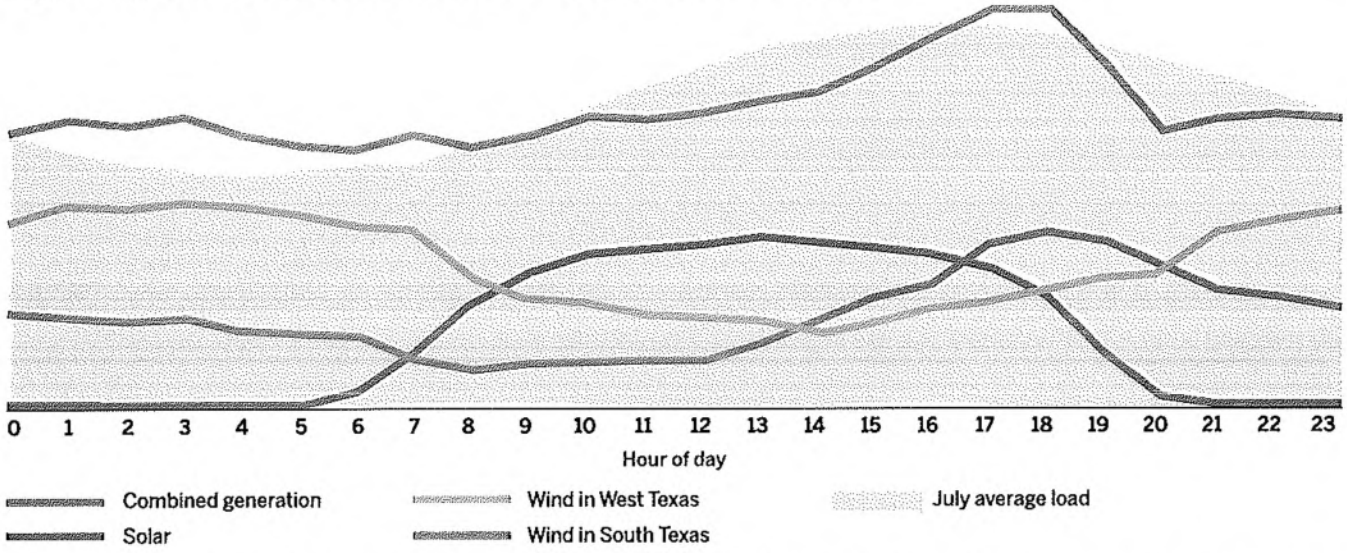
Distributed storage presents other issues and opportunities, as it is a capital-intensive peaking resource with no direct fuel costs, dependent on charging from other resources, and provides a variety of energy, capacity, transmission, distribution and **ancillary services** to the system and sometimes backup supply to host customers. Storage may displace T&D investments, reduce fuel consumption, enable renewable energy integration and provide emergency service at customer sites. Each of these functions has a different place in a modern cost allocation study.

A portfolio of energy efficiency measures reduces energy requirements, generation capacity requirements and stress on T&D equipment, as well as reduces customer billing determinants. As discussed in Section 14.1, energy efficiency expenditures can be classified and allocated in proportion to the benefits they produce. The plans and evaluation reports of the program administrator (the utility or a third party authorized to provide those services) generally provide sufficient data on the load shape and class distribution of load reductions. Since energy efficiency costs are recovered through a variety of mechanisms (rate based or expensed, through base rates or a discrete conservation surcharge or **rider**), the cost allocation should reflect the cost recovery method.

The costs of demand response programs — direct load control, customer load automation (e.g., setback thermostats) and price-responsive load (e.g., critical peak pricing) — should similarly be apportioned to reflect their benefits, so that cost-effective demand response is a net benefit to both participants and nonparticipants.[59] An hourly assignment method, where the costs of demand response are apportioned

59 Under conventional rate designs, participants (and their classes) generally retain a smaller share of the benefits of demand response (other than incentives for program participation, which may include peak-time rebates) than of energy efficiency programs. Depending on the program design, the incentives for the participants may be reflected in cost allocation and rate design through (1) reduced allocation of costs to the participating customers and classes to reflect improved load shape, (2) payment of incentives (including peak-time rebates) and allocation of those and other utility expenditures as costs, or (3) a combination of the two, as long as the benefits are not double-counted. Dynamic peak pricing may encourage demand response without explicit incentives, with the cost allocation to the participants' class reflecting the improved load shape.

Figure 24. Illustrative Texas wind and solar resource compared with load shape



Sources: Adapted from Slusarewicz, J., and Cohan, D. (2018). *Assessing Solar and Wind Complementarity in Texas* [Licensed under http://creativecommons.org/licenses/by/4.0]. Load data from Electric Reliability Council of Texas. (2019). *2018 ERCOT Hourly Load Data*

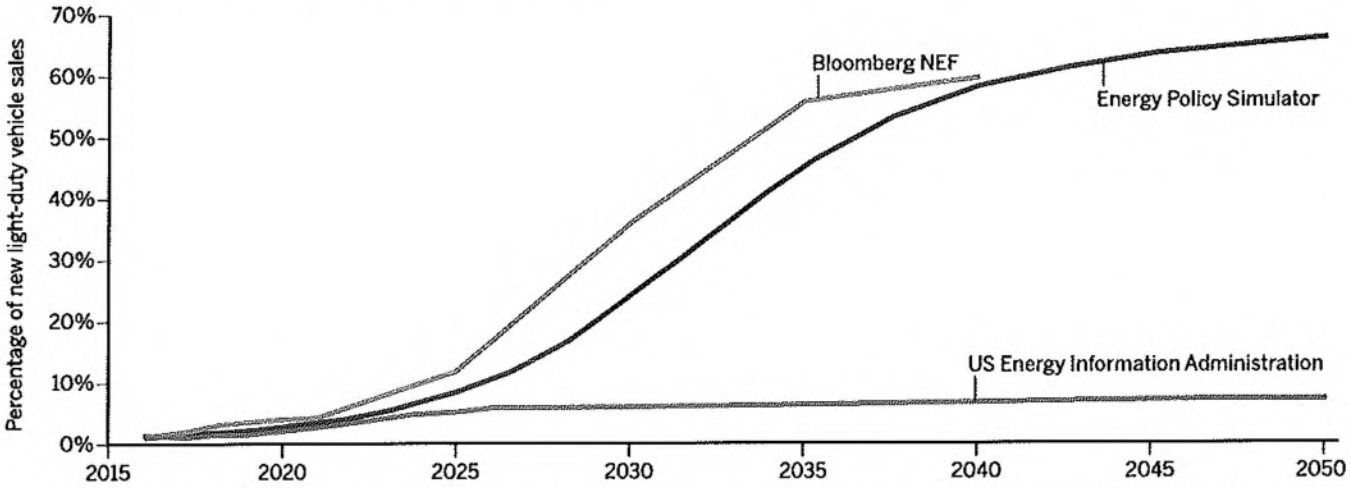
to the hours when it is called upon (to reduce load or provide operating reserves), may help match costs to benefits across classes.

7.1.3 Beneficial Electrification of Transportation

Electric vehicles currently use less than 1% of the nation's electricity, but that is expected to rise sharply in the next two decades. However, the precise rate of expansion is uncertain. Figure 25 shows three alternative projections for sales of electric vehicles (Rissman, 2017).

For cost allocation purposes, there are two interrelated issues: how to treat existing customers who adopt EVs as well as new dedicated EV charging accounts, and how to allocate the costs of new utility EV programs, both for demand management and investments in charging stations.

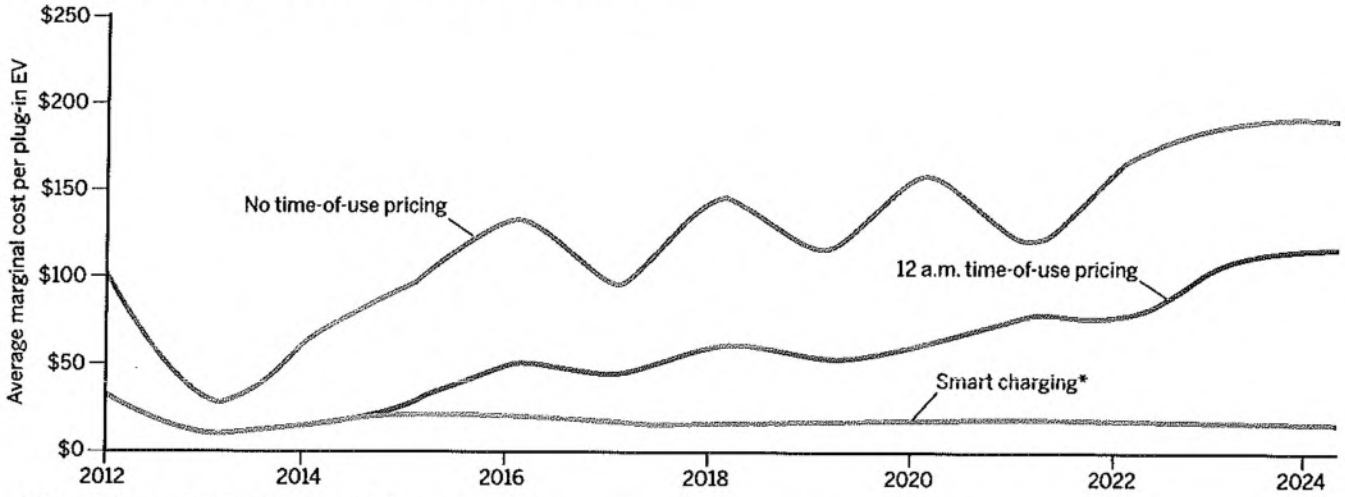
Figure 25. Forecasts of electric vehicle share of sales



Note: Projections of U.S. market share of EVs are from the Energy Policy Simulator 1.3.1 BAU case, the Energy Information Administration *Annual Energy Outlook 2017* "No Clean Power Plan" side case, and the Bloomberg NEF *Electric Vehicle Outlook 2017*.

Source: Rissman, J. (2017). *The Future of Electric Vehicles in the U.S.*

Figure 26. Estimated grid integration costs for electric vehicles



*Not including costs to implement smart charging technology

Source: Sacramento Municipal Utility District, personal communication, July 8, 2019

EVs are first being adopted in light-duty vehicle market segments, which primarily equates to residential adoption. These EVs are charged predominantly at home; there is a general consensus that home charging comprises over 80% on average (U.S. Department of Energy, n.d.). This home EV charging represents a substantial, but not totally unprecedented, amount of new consumption for a residential customer. The annual consumption for an EV represents slightly less than the consumption required for a typical electric water heater (U.S. Department of Energy, n.d.). If uncontrolled, however, this additional consumption could change the load profile significantly for this subset of customers, potentially leading to additional system costs. For example, if EVs begin to charge at home right after the workday ends and the sun is setting, then this could increase system peak and exacerbate ramping issues.

Between rate classes, changes in load profiles can be easily accounted for in future rate cases as long as there is sufficient load research data on the issue. However, there could also be significant changes in customer load profiles within each rate class. As a result, some analysts have suggested that residential customers with EVs should be a separate rate class. As a threshold matter as discussed in Section 5.2, it is an empirical question whether customers with EVs have distinct cost characteristics from other customers in the same rate class and whether EV adoption is high enough within the rate class to have an impact on the other customers. However, assuming for the sake of argument that these thresholds are crossed, there are alternative ways to address the issue. It is not a given that EV charging will increase system peak or otherwise negatively impact other customers. Time-of-use rates and other demand management programs can significantly lessen these impacts. Figure 26 shows estimated grid integration costs for uncontrolled EV charging and two alternative methods for managing EV load (Sacramento Municipal Utility District, personal communication, July 8, 2019).

Many jurisdictions are moving toward widespread TOU rates for residential customers. If these rates are mandatory for residential customers or even just the default for residential customers with EVs, then that would likely eliminate any cross-subsidy issues between residential customers with and without EVs. Similarly, EVs can be easily integrated into other demand management programs, or programs specific to EVs can be examined.

At some point, similar issues may arise for workplace charging for light-duty vehicles, and it will be desirable to concentrate charging into the hours when generation and delivery system capacity is available and unused. For example, it may be desirable to concentrate workplace EV charging during periods when solar generation is prevalent.

As of this writing, many different heavy-duty EVs are beginning to be adopted. Many jurisdictions have started to adopt electric buses, and a wide range of electric trucks are under development, from postal and parcel urban delivery vehicles to long-haul semitrailers. Fleets of these vehicles will have charging requirements measured in MWs, not kWs, and it may be desirable to locate these charging facilities where they can be directly served from the transmission network, avoiding the primary distribution network altogether. In this case, these sites will be more like large industrial high-voltage customers for cost analysis purposes. Making potential customers aware of this option, to access lower-cost power by locating adjacent to transmission capacity, may help guide the evolution of this market segment on an economical pathway.

Lastly, the development of public DC fast charging, thought by many to be a prerequisite to scale up EV adoption dramatically, is posing a range of new public policy issues. DC fast chargers allow for significantly faster recharging than other charging methods, which may be necessary for a variety of EV use cases, including long-distance travel and adoption in areas where residents cannot charge at home. The power rating of DC fast chargers is typically over 50 kWs per charging port and could increase significantly (Nicholas and Hall, 2018). These characteristics mean that DC fast chargers typically cannot be installed for single-family residential customers. However, DC fast chargers can be installed at many commercial and industrial locations with a sufficient service capacity (e.g., a mall) or connected directly as a stand-alone C&I customer with a separate account.

Many jurisdictions have been wrestling with the proper rate class and rate design for stand-alone DC fast charger accounts. This is because these accounts have a load profile without an obvious correspondence to other C&I rate classes. These accounts have typically been placed in rate classes with significant demand charges. However, given the high kW power rating and low utilization rates at this early stage of EV adoption, high demand charges lead to extraordinarily high bills for these fast charging accounts, at least on an average cost per kWh basis. Given the broader public policy need for public DC fast charging, a number of jurisdictions have begun to take steps to lower bills for these accounts, either through outright discounts or alternative rate structures. To date, there are significant tensions in all of the proposed solutions for these DC fast charging accounts. Given the significant site infrastructure needed to connect the uncontrolled power draw from DC fast chargers, the customer NCP demand for these accounts could be a relevant cost driver. RAP's preferred C&I rate design accounts for this by requiring modest customer NCP demand charges for site infrastructure ($1 to $2 per kW) with other elements of the rates established on a time-varying per-kWh basis. Such a rate would provide the right blend of incentives to manage usage for DC fast chargers through storage or other techniques. As a result, reforming rate design for C&I customers could be the optimal solution to this issue, instead of establishing separate rate classes for DC fast charging or providing arbitrary discounts under existing C&I rate designs.

Several states have also begun to implement utility EV programs, and many more states are considering policies in this area. Expenditures by regulated utilities to support electric vehicles are justified on a wide array of grounds:

- Societal benefits: public health and climate benefits, energy independence and reduced noise.
- Electric system benefits to all ratepayers: new load at beneficial off-peak hours and flexible new loads to optimize ramping.
- Benefits to participating customers and EV drivers: increased convenience, lower total driving costs and the potential to attract new customers to retail businesses.

One category of utility EV programs is quite similar to other energy and demand management programs. In the aggregate, uncontrolled EV load could be a significant addition to peak load that drives many system costs. These utility EV programs encourage, or in some cases ensure, that EV charging will take place during off-peak hours to minimize system stress and long-run electric system costs. The justifications for these programs and the principles for allocating the costs are not very different from other energy management and demand response programs, with functionalization, classification and allocation according to the benefits of the program or alternatively to classes in proportion to customer participation.

In contrast, another major category of utility EV programs does raise new questions. Utility expenditures and investments in support of charging infrastructure are taking a wide variety of forms, including rebates, additional allowances for interconnection costs, and direct utility ownership and operation of end-use charging stations. In most of these programs, participants are expected to bear some of the costs of the charging station, either upfront or ongoing, although a few programs may include full utility ownership and responsibility for all ongoing costs. Drivers of EVs are certainly the most direct beneficiaries of these programs, but there are a wide range of potential benefits for other ratepayers and society at large. Depending on the perspective, this could justify a wide range of cost allocation techniques, including:

- Direct assignment to the customer classes receiving free or subsidized equipment.[60]
- Allocation to all classes in proportion to class revenues or energy use to reflect the benefits to each class from increased sales and reduced average costs.
- Direct assignment to EV program accounts or a broader group of identifiable EV customers as program beneficiaries.[61]

These programs are still quite new at the time of publication for this manual, so many of the important issues are only beginning to be investigated. This is further complicated by cross-cutting issues, such as the integration of energy management programs into utility EV infrastructure investments and the impacts of cost allocation decisions on the competitive EV charging market and charging station providers who do not (or cannot) benefit from utility support.

One logical outcome across these issues could be applying fully loaded time-varying rates to identifiable EV accounts, which may provide higher incremental revenue than incremental costs in those hours. This would have the effect of socializing a substantial portion of EV program costs across a broader group of ratepayers. This would be consistent with efforts to jump-start an infant industry. EV charging station program cost responsibility could be more directly concentrated toward EV drivers over time. This could mean specialized ongoing cost recovery mechanisms, including direct assignment of identifiable EV-related costs. However, a jurisdiction that is seeking to accelerate EV adoption would certainly be free to apply short-run marginal cost-based economic development rates to EV charging development while simultaneously socializing EV program costs to all ratepayers.

7.1.4 Distributed Energy Resources

Over the last decade, DERs, particularly rooftop solar, have gained significant traction in many jurisdictions. Many states adopted net metering rules for rooftop solar and other eligible technologies in the 2000s.[62] The federal government also established the investment tax credit for commercial and residential solar systems in 2005, which was thereafter extended and expanded to other solar applications. Starting in the late 2000s, costs for solar panels started to drop quickly. These policies and trends, in addition to a range of additional state policies and incentives, have created a significant new market for rooftop solar. As shown in Figure 27 on the next page, adoption of residential solar accelerated to significant levels in the mid-2010s, with more than 2 GWs of installations annually from 2015 through 2018 (Wood Mackenzie Power & Renewables and Solar Energy Industries Association, 2019, p. 20).

Customer-sited adoption of solar can raise several cost allocation issues. Unlike EVs, distributed solar reduces customer load. At the macro level, for utilities without **decoupling**, this can lead to underrecovery of revenue and necessitate more frequent rate cases. If adoption of distributed solar is captured in the load research data, then cost allocation between rate classes may change over time depending on the cost allocation techniques used.

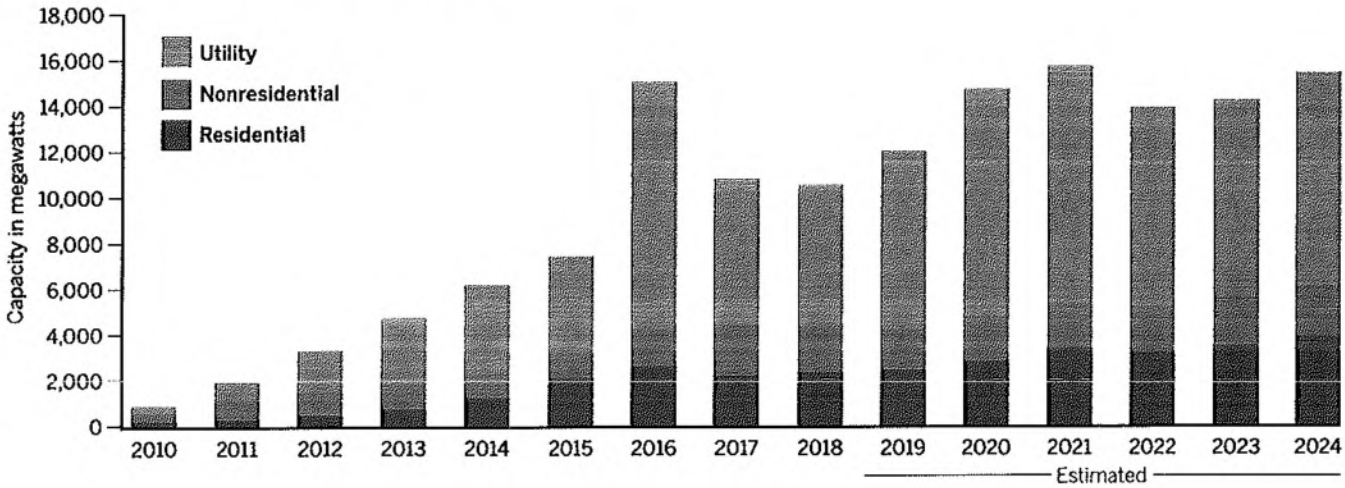
The more difficult issue that jurisdictions around the country have been wrestling with is the possibility of

60 The number of EV program participants in a class, but not the total number of customers in the class, may be relevant to allocation of the costs.

61 There are a number of potential variants on this. Direct recovery of costs from a given customer for installation at that customer's site over time would act as a financing mechanism for that customer. However, specific program costs (e.g., a DC fast charger program) could be recovered through a combination of subsidies from other classes and an ongoing per-kWh basis from the accounts that participated in that program.

62 The 2005 Energy Policy Act added net metering to the PURPA standards that each state was required to consider. Pub. L. No. 109-58 § 1251. Retrieved from https://www.congress.gov/109/plaws/publ58/PLAW-109publ58.pdf

Figure 27. US solar photovoltaic installations



Source: Wood Mackenzie Power & Renewables and Solar Energy Industries Association. (2019, March). *U.S. Solar Market Insight*

intraclass cross-subsidies between customers with solar and those without. Many utilities have proposed special rate designs, changes to net metering rules and separate rate classes for customers with solar. As always, the threshold issue for creating a new rate class is whether customers with solar are having material impacts on the other customers. Some utilities and consumer advocates argue that net metering rules allow customers with solar to pay less than their fair share of system costs. It is important to quantitatively evaluate these concerns before making policy adjustments to address them.

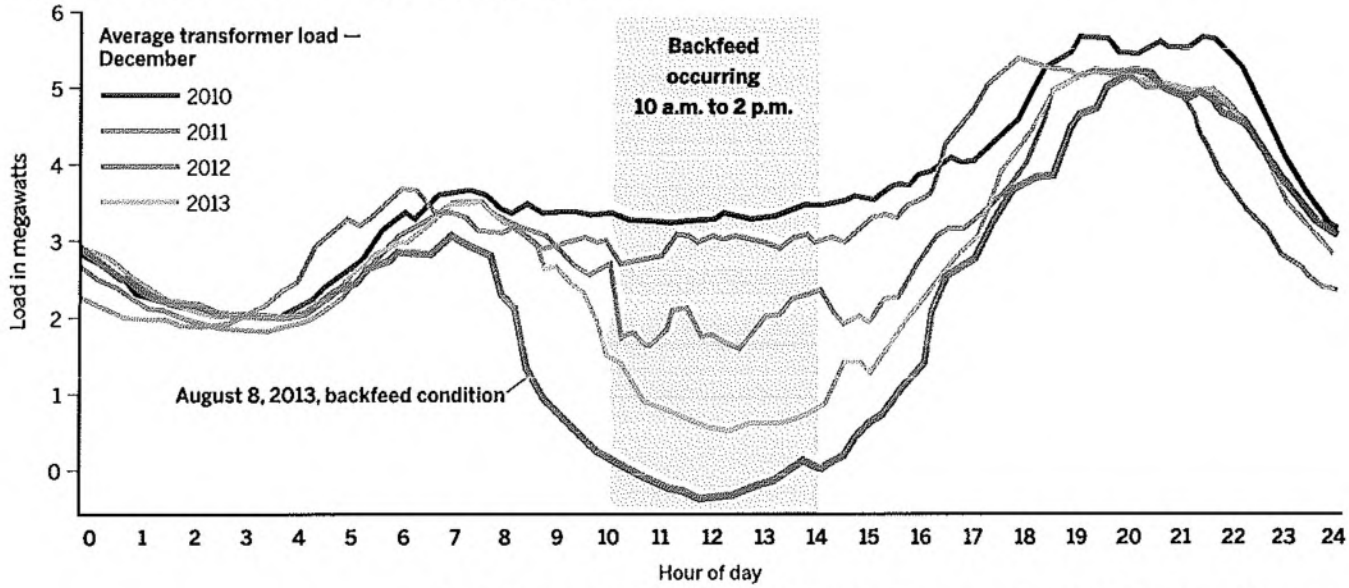
To begin, the levels of distributed solar adoption across the country are quite uneven. While many jurisdictions have significant levels of adoption, particularly those with either strong solar resources (such as California and Hawaii) or supportive state policy environments, many other jurisdictions have low levels of adoption. In jurisdictions with low levels of adoption, the impacts on other customers are necessarily quite small. If only 1% of class load is accounted for by distributed solar, then the worst-case scenario is approximately 1% higher bills for nonparticipating customers, with a strong likelihood of lower impacts given the offsetting benefits of solar generation.[63]

Even in jurisdictions with significant penetration levels of distributed solar, there have been robust debates about the existence of significant cross-subsidies and the proper means to address them. As a general matter, most proposals to establish separate rate classes for distributed solar have been denied so far.[64] Utilities have also proposed higher customer charges and special demand charges for solar customers, which have not been widely adopted. However, a variety of rate design changes have been adopted to better align compensation with value and reduce the potential for unreasonable cross-subsidies. California has begun to address these issues by requiring new residential net metering customers to be placed on TOU rates, a measure that is integrated with a move toward TOU rates for residential customers more generally (California Public Utilities Commission, n.d. and 2016). New York's Value of Distributed Energy Resources proceeding has set up specialized export credit compensation for large distributed energy projects, which include values

63 Net ratepayer impacts from solar policies depend on many factors. In jurisdictions with significant renewable portfolio standard costs or separate solar incentive programs, these costs can be quite different than in jurisdictions where the primary solar compensation policy is net metering. It is important to distinguish whether costs to nonparticipating ratepayers are occurring because of the RPS, dedicated solar incentive programs or net metering policies.

64 The exception to date is Kansas, although separate rate classes for solar customers have been authorized by legislative action in additional states (Trabish, 2017). At the time of this writing, this area of policy is rapidly evolving.

Figure 28. Substation backfeeding during high solar hours



Source: Hawaiian Electric Company. (2014, April 30). *Minimum Day Time Load Calculation and Screening.* Distributed Generation Interconnection Collaborative (DGIC) webinar

for energy, capacity, delivery and environmental externalities (New York Public Service Commission, 2017). Tensions in these debates include differentials between short-term and long-term avoided costs due to distributed generation and how to consider significant societal externalities such as greenhouse gas emissions.

Customer-sited storage is another DER that is expected to grow in importance in the coming decades. Storage can be used to change the load profile for adopting customers and even export energy to the grid if the jurisdiction allows it. Under flat volumetric rates, there is little incentive to manage energy usage with storage and little risk of unusually significant cross-subsidies. However, storage is becoming economically attractive in many jurisdictions to C&I customers that have high demand charges. These demand charges may not be well designed economically, and storage could allow these customers to lower their bills substantially. More generally, well-designed time-varying rates and demand charges can give the proper incentives for energy management through storage, but poorly designed rates will give customers correspondingly poor incentives.

Lastly, higher penetrations of DERs will raise new issues around the allocation of local distribution facilities. As more DERs are added, there will be some systems where primary or transmission voltage customers receive a portion of their power from generating facilities located along distribution circuits. Where this occurs, some provision should be made to treat a portion of the distribution investment as a generation-related cost. Figure 28 shows how some distribution substations may backfeed to the transmission system during solar hours, even if the solar facilities are sited exclusively on the rooftops of secondary voltage customers (Hawaiian Electric Company, 2014).

7.2 Changes to Regulatory Frameworks

As also introduced in Chapter 4, many new regulatory issues have arisen since the 1992 NARUC *Electric Utility Cost Allocation Manual*, and some older issues have become more prominent and widespread. These issues include:

- Restructuring and the emergence of organized wholesale markets and **retail competition**.
- Holding company issues due to widespread mergers and new utility conglomerates.
- Performance-based revenue frameworks.
- Proliferation of **trackers** and riders recovering costs outside of rate cases.
- New types of public policy programs.

- Consideration of differential rates of return in cost allocation studies.
- Recovery of **stranded costs**, assets with changed purposes and exit fees.

7.2.1 Restructuring

A few issues in cost allocation are specific to restructured electric utilities and **distribution system operators**.

Administrative and General Expenses

The most important of these issues may be that A&G costs become a larger share of total costs. As utilities have been restructured, not all have trimmed their management ranks or reduced executive compensation in proportion to the reduction in gross revenues. Regulators may need to use utilities that have never had production as proxies to determine appropriate cost levels to be assigned to distribution services and the apportionment of that cost. Even for **restructured utilities** that do not own generation assets, there are costs of maintaining involvement in regional power planning activities, ISO and RTO involvement and NERC involvement that are more closely related to power supply than the ownership and operation of a distribution system. Memberships in various industry organizations may be power supply-related as well.

Provision of Generation Services

In most states allowing retail competition, the distribution utility also procures and offers, at cost, a **default power supply** service for customers who do not choose an alternative retail electricity supplier.[65] These costs normally will not be included in the cost of service study during a base rate case because they apply only to an optional service and are set through a separate proceeding, generally by competitive bidding to supply individual classes based on their historical load shapes.[66] Any costs incurred by the utility to procure these services should be recovered through the default service, without affecting rate case revenue requirements.

Currently, default service is typically offered on a single residential load profile. We anticipate in the future this will become more granular,[67] at least with respect to time of day and season. This may be done with separate default tariffs for different subclasses of customers, such as multifamily, electric heating or electric vehicle owners. Or it may be done more simply, with a time-varying default service option that applies the same rates to all customers in each period, resulting in different average rates to customers with different usage patterns. A regulator may choose to reconfigure, for retail pricing purposes, these costs on a time-varying basis; if this occurs, the rate analyst must track this change into the cost allocation process.

Some ISOs (for example, ISO-NE, MISO, PJM) apply separate capacity charges and energy charges for power supply delivered to retail providers. Others (such as ERCOT) have eschewed capacity markets, instead concentrating on time differentiation of costs on a volumetric basis and allowing competitive energy prices to rise to levels reflective of scarcity and the value of lost load.[68]

The rate analyst may be in the position of second-guessing the ISO pricing, just as has been the case for natural gas utilities and FERC-approved pipeline charges for decades. If the ISO has treated some costs as capacity-related that can be more economically avoided with storage or demand response within the utility service territory, it may be appropriate to recharacterize these ISO costs as partly capacity-related costs and partly energy-related costs.

Transmission Costs

In addition to billing for generation capacity and energy in most cases, all ISOs/RTOs bill for transmission service. Most assign transmission costs, project by project, to geographic areas, based on the historical ownership of older

65 Texas has not had any form of default supply since restructuring; all customers must choose a retail electricity supplier.

66 If the utility procures default service at a single price for multiple classes, the regulator should consider whether to differentiate the rates to reflect differences among the classes.

67 See Hledik and Lazar (2016) for a discussion of future pricing options to enable optimal utilization of DERs to meet system and local capacity requirements.

68 We note that the costs of the Alberta capacity market are spread on a time-differentiated volumetric basis rather than a traditional demand charge; this may be a useful model for U.S. ISOs. For a more robust discussion, see Hogan (2016).

facilities and the loads justifying new facilities. If those charges are billed on a capacity basis, the pricing may exceed the cost of avoidance of some transmission capacity but still be necessary for moving energy at nonpeak hours.[69] In this situation, the analyst may need to consider whether some transmission costs are imprudent and should be excluded from the revenue requirement or, perhaps due to how the assets are used, to split these costs between demand and energy.

There are many circumstances where the analyst must look through ISO pricing to determine an appropriate basis for retail cost allocation. For example, ERCOT charges for transmission primarily on a 4 CP basis for the summer months (June through September). Similar approaches may be used in FERC-regulated transmission agreements among affiliates outside of ISOs. These pricing methods and the resulting allocations are administrative simplifications and do not necessarily reflect cost causation. The ISO cost allocations do not control the retail allocation of transmission costs among customer classes or the manner these costs are reflected in rate design.

7.2.2 Holding Companies

There have been more than 100 mergers of electric utilities since the 1992 NARUC manual. This phenomenon was accelerated in 2005 when Congress repealed the Public Utility Holding Company Act. This has resulted in very different corporate relationships than existed in the 1980s and has created myriad issues to consider in the cost allocation process, from executive compensation to interservice allocation procedures.

Most utility mergers and acquisitions are justified by projections of more efficient management and a corresponding decline in administrative costs. Determining whether these promises have been realized is a revenue requirement issue beyond the scope of this manual. But the apportionment of administrative costs among unregulated and utility functions, and among utilities within the holding company, are often part of cost allocation. The increased complexity of utility holding companies makes this task more difficult.

Many state utility commissions have taken steps to exclude from the revenue requirement any incentives such as higher executive compensation that reward shareholder benefits (such as for a higher stock price) or rewards for good performance in unregulated operations. Determining the portion of executive compensation that is attributable to the utility operations, as contrasted with corporate profit maximization, is not straightforward. This question may be approached by using senior management costs at public agencies (such as state departments of transportation, health and education or universities) as a proxy for the portion of executive compensation that should be allocated to utility service. Large public agencies may have budgets, employee counts and subordinate levels of management comparable to those of utilities.

Different business operations of a modern utility holding company have different risks and rewards. Although management of a distribution utility is complex, the amount of innovation and risk is fundamentally different than in other business units of the holding company. As noted by the U.S. Supreme Court:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property it employs for the convenience of the public equal to that generally being made at the same time and in the same region of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties, but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures.[70]

By the same logic, a utility is entitled to recover the management costs of a company with similar complexity and risk but not necessarily those of a more speculative business operation.

Shareholder service costs — such as the cost of maintaining shareholder data, issuing dividends, issuing new capital stock and annual meeting costs — must be

69 The Vermont regulator has regularly identified specific nodes where increased efforts for energy efficiency can reduce the need for transmission or distribution capacity upgrades (Vermont Public Service Board, 2007; Vermont System Planning Committee, n.d.). This may provide a foundation for classification of ISO transmission charges and for functionalizing some of these energy efficiency investments as transmission-related or distribution-related capacity costs.

70 Bluefield Water Works v. Public Service Commission, 262 U.S. 679, 692-93 (1923).

apportioned between the non-utility enterprises and the electric utility. Simple methods such as gross revenue or gross capital may be used; more complex methods looking at the number of employees, the contribution to earnings or other factors may also be appropriate.

Holding company insurance costs are substantial. Some are directly related to the utility service business, some are directly related to non-utility operations, and some are shared expenses. As with administrative costs and shareholder service costs, the most appropriate allocation method may need to rely on proxies of enterprises with simpler structures.

7.2.3 Performance-Based Regulation Issues

Performance-based regulation has emerged as a central theme in utility regulation. Although the genesis of PBR long predates the 1992 NARUC cost allocation manual, new and different approaches are being developed and implemented today. Early PBR mechanisms were simple price caps or discrete adders for specific investments.[71] The relevant issue for this manual is how to treat PBR costs and benefits in the cost allocation process.

The central concept of PBR is greater emphasis on the achievement of public policy objectives — such as lower customer costs, improved fuel cost performance, better reliability, increased reliance on preferred resources or other discrete goals — coupled with lower reliance on investment levels as a determinant of earnings. This tends to increase the operating expenses to cover the incentives while decreasing both investment and operating expenses when the incentives achieve cost savings.

The incentives may be in the form of a higher allowed rate of return based on achieving policy goals or discrete bonuses for achieving specific objectives. Similarly, penalties for underperformance can take a number of forms. The costs to ratepayers of PBR may include the incentives paid to shareholders as well as expenditures undertaken to achieve the PBR goals.[72] Those costs should be allocated to classes in proportion to the benefits they receive, and penalties returned to ratepayers should be allocated in a manner similar to the distribution of the excess costs that prompted the penalties.

One form of PBR is to provide for multiyear rate plans, where the incentive between rate cases is to achieve designated policy goals. Specific rewards for achievement provide higher earnings between proceedings, rather than mere cost control. This may have the effect of extending the period between general rate proceedings, making it more important that cost allocation in rate proceedings be given adequate attention. This is important because the results may be in place for a longer period than with conventional regulation.

7.2.4 Trackers and Riders

The rapid proliferation of tariff riders did not feature in the 1992 NARUC cost allocation manual at all. The earliest of these were **fuel adjustment clauses** adopted in the wake of the oil embargos in the 1970s, but they have now spread to many other categories, including energy efficiency programs, infrastructure spending, nuclear decommissioning and taxes. These riders cause revenue levels to track changes in costs between rate cases in specific categories. Some utilities have 10 or more separate tariff riders, each adjusted between rate cases.

Cost of service studies should be designed for compatibility with the methods that will be used to adjust costs between rate cases. Adjustments between cases may need to be simpler for administrative convenience and may not track cost study results accurately. To maintain consistency, the cost of service study may allocate all costs, with costs to be recovered through riders netted from class revenue requirements as the final step before the design of base rates. Alternatively, allocations of particular cost components from the cost of service study can be applied to the allocation of rider costs (e.g., the residential class might be assigned 34% of any primary distribution upgrades, 30% of purchased renewable energy, and so on).

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71 For example, in 1980, the Washington State Legislature approved a 2% incremental rate of return for energy efficiency investments. Two decades later, the Nevada Public Utilities Commission adopted a similar incentive. Both have been allowed to expire.

72 For example, an incentive mechanism to control fuel costs may require capital investments to improve generating units.

Many tariff riders recover only the difference between actually incurred costs and costs estimated in a rate case, which could be reasonably expected to be relatively small. As a result, it often seems relatively fair and administratively efficient to pass these costs on in a simple way. Larger costs may require more detailed methods to track the broader issues laid out in this manual. If general rate cases occur with reasonable frequency, the divergence of riders from the cost of service study between general rate cases probably will be minor.

Many riders are allocated to classes on one of two simple models: a uniform cents-per-kWh surcharge or a uniform percentage surcharge. The uniform cents-per-kWh approach is appropriate for costs associated or correlated with energy usage. The percentage surcharge is rarely appropriate, since it will allocate costs proportionate to all the rate case costs, from meters to substations to (for vertically integrated utilities) baseload generation.

A wide variety of costs are routinely recovered through riders and trackers in many jurisdictions. These costs include the following.

Fuel and purchased power: Historically, most of these costs have been recovered through rate riders on a uniform cents-per-kWh basis across all classes.[73] Various fuels and purchased resources (renewables, combined cycle plants, combustion turbines, storage resources) provide different mixes of services. It may be appropriate to unbundle these costs by time period, so that charges more accurately reflect the hours in which the resource is useful and hence the mix of customer loads that use it. The typical uniform cents-per-kWh fuel adjustment clause may be replaced by a more granular rider, with at least time and seasonal differentiation (Hledik and Lazar, 2016). To the extent feasible, the allocation of costs in the rider should reflect the approach used in the general rate proceeding. If costs associated with purchased power are not separated between base rates and the adjustment mechanism in the same manner as utility-owned generating assets, a double-recovery problem may occur, with base rates recovering hypothetical investment costs to serve load growth, while an adjustment mechanism also recovers these costs.

Decoupling and weather normalization: Many regulators have adopted measures to insulate utility net income from variations in sales volumes. Some of these mechanisms are decoupling adjustments that take all sales variations into account, while others are strictly limited to sales variation due to energy conservation program deployment or weather. Most of these mechanisms adjust costs that are included in the cost allocation study at test-year levels. The allocation method used for these riders between rate cases should reflect the allocation of costs in the general rate cases. For example, customer costs do not vary with sales levels and should not be used in allocating the costs and credits from weather normalization.

Required and approved new projects: Some jurisdictions allow utilities to adjust rates to reflect new investments or operating costs (perhaps limited to specific categories, such as pollution control equipment, storm protection or ISO-approved transmission). The method used to allocate changes in costs between rate cases should be consistent (even if simplified) with the method used to allocate costs in general rate cases.

Inflation and actuarial changes: A few states allow flow-through between rate cases of inflation, attrition, statutory tax rates or other exogenous changes in costs, such as labor contracts or pensions. Where possible, these adjustments should be allocated in a manner similar to that used for the underlying costs.

Flow-through of changes in property taxes: Property taxes affect all elements of service and are generally assessed on the basis of appraised value, which (depending on the jurisdiction) may be very different from the gross and net book values used to set the revenue requirement.

Flow-through of municipal taxes and franchise fees: Some gross revenue taxes and franchise fees are imposed by municipalities and are often directly assigned to customers in that municipality and collected on the same basis they are imposed (e.g., a uniform percentage of gross revenue).

Storm damage: Regulators often allow recovery for storm damage in proceedings separate from general rate cases. In many cases, balancing accounts are created for

73 Some utilities adjust power supply riders by estimated line losses by class.

storm damage recovery; after large storms, the amount to be recovered may be adjusted. Storm damage typically affects primarily distribution and transmission costs. The method used for apportionment of changes in tariff riders for storm damage should generally follow the methods used in rate cases for apportioning the relevant costs (but not the cost for unaffected T&D costs, such as meters in most storms).

Regional transmission charges: Transmission charges imposed by an RTO or ISO are subject to change between rate cases. These changes may flow through to customers through a broader generation-cost tracking mechanism or a separate transmission rider. To the extent feasible, the costs should be classified and allocated using the same approaches used in allocating bulk transmission costs in the cost of service study. Because peaking assets commonly are located inside or near load centers, bulk transmission requirements tend to be driven more by access to low-cost energy resources, such as baseload generation, as discussed in Chapter 10. If some simple allocator is required for transmission costs outside full rate reviews, an energy allocator is likely to be reasonable.

Earnings sharing mechanisms: Some states require utilities to share earnings that exceed some threshold above the allowed rate of return; these are common in conjunction with decoupling mechanisms. Because overall earnings are a broad measure of utility costs compared with revenues, any earnings sharing will likely be spread across all functional areas and should be reflected as a percentage adjustment to overall rates.

7.2.5 Public Policy Discounts and Programs

Regulators and legislatures have dictated that utilities offer a range of public policy programs, mostly falling into two categories: (1) discounts or surcharges for certain categories of customers, such as low-income discounts, economic development discounts for industrial customers and area-specific surcharges; and (2) resource-specific incentives for energy efficiency, storage and renewables (including distributed solar).

These programs result in additional costs or redirected revenue requirements to be recovered through base rates, riders or a combination of the two. These revenue requirements may be included in the allocation of total costs, with base rates set to exclude the revenues expected through the riders, or the base rate revenue requirements and the riders can be allocated separately. In any case, the revenue requirements should be allocated among classes in a manner consistent with causality or benefits, without creating excessive administrative burdens in the updating of riders.

Public policy programs for specific resources or resource types (a renewable portfolio standard or other types of clean energy standard) may be justified on current economic benefits, environmental benefits, reliability improvements or the acceleration of emerging technologies and industries with future potential benefits. The costs of these programs are usually allocated either on the basis of program participation by rate class or in proportion to system benefits as they are expected to accrue across rate classes.

7.2.6 Consideration of Differential Rates of Return

Historically, most cost allocation studies have applied a single rate of return, based on the utility cost of capital, to all capital investment components of the system and to all customer classes. In a more competitive utility environment, this may no longer be appropriate.

Rating agencies and others recognize some utility assets, such as generation, as riskier than other assets, such as distribution. Many utilities have experienced significant disallowances in cost recovery for generation, but the same generally has not been the case with distribution investment. Applying a function-specific rate of return in computing class cost responsibility will assure that this cost follows causation and benefit.

Similarly, some utility customer classes may be viewed as riskier than others. This may be customers with electric space conditioning, whose usage is more temperature-sensitive, creating variability in sales from year to year. Or it may be entire classes of customers whose usage varies with economic conditions, creating what financial analysts call systematic risk that raises the utility cost of capital. Applying a class-specific rate of return in computing class cost responsibility

will ensure that low-risk classes do not pay costs more properly attributable to higher-risk classes.

A differential rate of return can be reflected either by assigning different costs of equity and debt to higher- and lower-risk parts of the enterprise, or by assigning a less-leveraged capital structure to the riskier parts of the enterprise and a more leveraged capital structure to the lower-risk parts. Moody's Investor Service applies a higher "business risk" score to generation than to distribution plant. This is then reflected in a higher equity capitalization rate, and thus a higher rate of return requirement, for generation plant (2017, p. 22). This translates into a differential rate of return requirement by customer class because different customer classes use a different mix of generation and distribution assets relative to their total revenue.

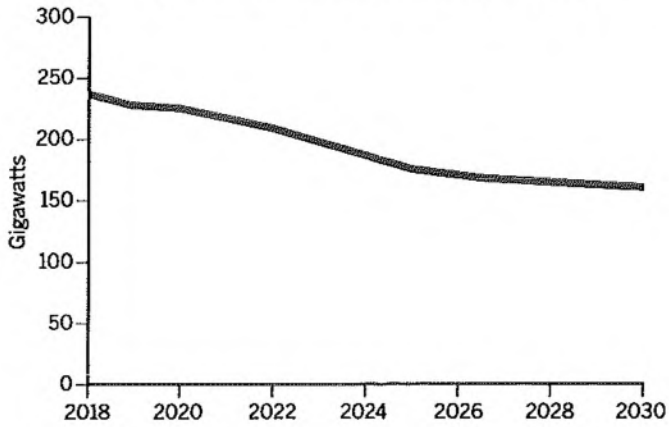
7.2.7 Stranded Costs, Changed Purposes and Exit Fees

Regulators will face several challenging issues as technology evolves in the electric power industry. Among these will be issues of stranded costs and changing purposes of past investments. Stranded costs occur when an asset is retired prior to being fully depreciated or when an asset is sold at a market price that is below the level included in rate base. Stranded costs were quite significant when the telecommunications industry evolved to computer switching and digital transmission after restructuring in the 1990s and 2000s. The issues will be at least as significant regarding the retirement of current coal and nuclear units. But some assets will be redeployed; for example, coal plant sites that formerly operated as baseload resources may be repurposed to support gas-fired peakers. Transmission lines originally built to serve remote baseload power plants may be redeployed to bring variable renewable energy. These changes to asset usage will raise unique cost allocation issues.

Generation

Historically, the largest source of stranded costs in the electric industry has been baseload generating resources. Tens of billions of dollars were invested in nuclear units that were abandoned prior to completion in the early 1980s. Many of the nuclear plants that were completed closed long before they were fully depreciated, due to severe damage (e.g., TMI 2, Crystal River, Trojan, Rancho Seco and San Onofre), large investment requirements or unfavorable economics. Today, innovation is rendering many units uneconomic in a narrow financial sense, excluding externalities of any kind, even when they are still mechanically sound. As shown in Figure 29, the U.S. Energy Information Administration (2019) projects that nearly 100 GWs of coal generation will be retired between 2018 and 2030. Most of this is due to economic obsolescence, but it also reflects changing public policies around air pollution and climate.

Figure 29. Projections for US coal generating capacity



Source: U.S. Energy Information Administration. (2019). *Annual Energy Outlook 2019*

Economic obsolescence of coal plants is primarily a result of lower-cost wind, solar and natural gas.[74] Although some policymakers are considering whether these coal plants, or the broader coal industry, need to be supported with financial incentives, there has been widespread support for this coal retirement trend for both cost and environmental reasons. In contrast, many states have been implementing policies to slow or stop nuclear retirements, in part because of the plants' climate benefits. In many cases, regulators have been actively involved in the decision to retire these units through integrated resource planning processes. In some

74 Public Service Company of Colorado decided to retire two coal units at the Comanche generating facility in Pueblo after bids for wind and solar energy were so low that the operating costs of these coal plants were deemed uneconomic (Pyper, 2018).

cases, legislatures have driven the retirements. Although a retirement usually concludes with a regulatory determination of what part of the cost is recoverable, a separate decision must be made on how to reflect the allowed costs in the cost of service methods and rate design of the utility.

Cost allocation analysts are not typically charged with determining the portion of abandoned project costs that electricity consumers or shareholders should bear. However, if these costs are included in rates, analysts are charged with determining how to reflect those costs in utility cost allocation studies and ultimately in rate design. If the plants were allocated in one way when operating and that method changes after termination, then the costs are shifted from one set of customers to another.

In other circumstances, plants have been converted from their original purpose to different purposes. The most common of these are baseload units, originally built to provide year-round service, being converted to peaking or seasonal generation or held in reserve for droughts or other contingencies. The cost allocation framework for the new purpose may be fundamentally different from the historical method based on historical usage.

In all of these cases, the cost of service study must reflect the allowed costs for abandoned or repurposed units. Should the costs be allocated based on the original intended purpose? Or should these costs be allocated based on the last useful purpose for the units? There is no easy answer.

Similar issues arose from the divestment of generation assets during restructuring. In jurisdictions with restructured utilities,[75] millions of retail customers have begun taking generation services from retail electricity providers or public aggregators and no longer pay the regulated utility directly for power supply. In many cases, this was politically achievable only by providing a method to compensate the utility for any stranded costs. This compensation typically was accomplished through a nonbypassable per-kWh charge on all distribution system customers, although in some cases specific exit fees were established so that departing customers made a one-time lump sum payment. Often this was done without reference to how the underlying costs are allocated among classes.

During restructuring proceedings in New England, many of the mid-Atlantic states, Illinois and Texas, regulators used an incremental valuation approach to recover the difference between the embedded costs and market values of generation assets. This included:

1. The net plant for utility-owned generation minus the sales price for those assets. That difference was negative for most hydro and fossil assets and positive for most nuclear assets.[76]
2. Costs of decommissioning for retired plants, especially nuclear units.
3. Payments to terminate or restructure long-term power purchase agreements.
4. Profit or loss from operating any residual utility-owned generation and selling power into the competitive market.[77]
5. Annual differences between payments for continuing power purchase agreements and the value of the power in the capacity and energy markets.[78]

Stranded cost charges are set to recover the sum of categories 4 and 5, the amortization of the balances in categories 1 through 3, any carrying charges for unamortized balances and any over- or undercollections in earlier periods.[79] Categories 4 and 5, and hence the overall surcharge, may be positive or negative. The surcharge continues until the stranded capital costs are recovered (or gains distributed) and all continuing cash flows end. In some jurisdictions,

75 New York, New Jersey, Pennsylvania, Maryland, Delaware, the District of Columbia, Ohio, Illinois, California, Texas and most of New England, as well as some customers in Michigan and Oregon. In Canada, Ontario has restructured similarly.

76 Certain utilities, notably all those in Ohio and some in Pennsylvania, New Jersey and Maryland, were allowed to transfer their generation assets to an affiliate at an estimated market value, rather than imposing a true market test from full divestment.

77 This approach has been applied to generation for which sale has been delayed (e.g., several nuclear units) or is impractical (e.g., ConEd's generation units located at or serving its steam distribution system) and to resources, such as renewables, that the utility is allowed to develop.

78 Long-term wholesale sales agreements may be bought out or treated in the same manner as power purchase agreements.

79 The costs in the first three categories frequently were refinanced through low-risk bonds, in a process called securitization.

restructuring surcharges have continued into 2019, in some cases as a credit.

Lastly, **community choice aggregation** has raised a similar set of issues in California, in part because a choice of energy supplier is not allowed more generally, and the utilities have procured long-term supply resources for a variety of reasons. Locales that form community choice aggregators, primarily counties, are allowed to contract directly with generators for power supply, which may vary from the resource characteristics of the utility's standard supply. In the meantime, market supply costs have declined, especially for renewables, and the migration of customer generation requirements from the utility to the aggregators can result in some stranded power costs, at least according to the utilities. California has selected a complex solution, imposing a power charge indifference adjustment, a type of exit fee with annual updates, on the community choice aggregators to recover the difference between actual utility costs and market prices. Rather than having a single charge for all customers to cover above-market costs, California has created a highly controversial process to set a charge for the customers of the aggregators and the direct marketers. The California experience illustrates the benefits of consistent allocation across customers, as opposed to the development of special rates for special groups of customers.

Any charge for stranded assets or costs should be temporary, only until the specific costs regulators allow are recovered.

Transmission

There is less history with transmission abandoned costs, but many lines are now being repurposed. Originally they were built to connect distant coal or nuclear baseload generating resources to urban load centers. Many of these were classified and allocated in the same manner as the baseload generation, with at least a portion of the cost classified as demand-related and allocated on some measure of peak demand. Today, with new natural gas generation being sited close to load centers and older coal and nuclear baseload units retired, these lines are being repurposed to transport economic energy from distant markets, including opportunity purchases, or to carry power from new wind and solar generating resources.[80] This is a very different use and provides very different economic benefits to consumers.

Some transmission lines are disused due to generation retirement. Although the inclusion of these costs in the rate base of the owning enterprise is a revenue requirement issue, the classification and allocation of any cost allowed by the regulator is a cost allocation issue. Some transmission lines may become economically obsolete due to the deployment of DERs within the service territory, obviating the need for some distant generation and its associated transmission lines. In this situation, the rate analyst is faced with the question of how to classify and allocate the fully or partly stranded costs.

Some lines may be repurposed from providing firm service from baseload resources to providing seasonal economic service without a clear connection to peak demand. In this situation, the costs may still be fully justified as economic and in the public interest, but a change in allocation method may be justified. An hourly assignment method will ensure that these costs are recovered in the hours when the economic energy is flowing.

Distribution

There have been very few regulatory disallowances of any magnitude for distribution plant, in part because the mass accounting methods do not identify specific segments. For example, when a large industrial facility closes, the investment in distribution facilities serving it typically remains in the regulated revenue requirement and continues to be classified and allocated in traditional ways. But technological evolution may result in higher rates of retirement or repurposing.

Some assets will be disused at many hours, due to deployment of DERs. Some CHP facilities will be entirely self-sufficient much of the time, with reliance on grid-supplied energy only during maintenance outages or periods of economical options. Distribution lines originally designed

80 Clear examples of this are found in the desert Southwest, where retirement of coal units in New Mexico, Arizona and Utah that formerly served California utilities is freeing up transmission that is being repurposed for moving variable renewables. State legislation mandated the retirements; economic conditions are driving the repurposing of these facilities.

to provide continuous service may be used only for a limited number of hours. The rate analyst must consider which is appropriate: applying the same methods used before DERs were installed or a different classification and allocation method in light of the changed circumstances.

In some areas of Hawaii, distribution circuits are back-feeding to the transmission system at midday; these lines are now serving a power supply integration function for many hours of each day.

The flow may be bidirectional. Power will flow into the lines from distant generation or storage during hours of darkness and into the grid for redelivery during high solar hours. The cost may be entirely prudent, but the traditional allocation methods may not accurately assign costs to the beneficiaries. An hourly allocation method may be appropriate for these circumstances, with the costs flowing to the consumers actually using the power when it is generated, rather than being apportioned to the generators or to customers not receiving power at certain hours.

Cross-Functional Repurposing

There are myriad examples of utility resources once needed for a particular function being repurposed for an entirely different function. For example, a former power plant site may become a location for a distribution warehouse. The power plant was functionalized as generation and allocated based on demand and energy factors. The distribution warehouse is a component of general plant, and the allocation method may be very different. One challenge for the rate analyst is tracking changes in how assets are being used, to keep the allocation framework consistent with the utilization of the assets.

8. Choosing Appropriate Costing Methods

In general, facilities shared among multiple users, as well as expenses and investments benefiting all ratepayers, should be apportioned based on measures of shared usage. Facilities that are uniquely serving individual customers should be sized to their individual needs, and the costs should be directly associated with those customers. Overhead costs, such as A&G expenses and general plant, are not costs that are subject to a "technically correct" allocation.[81] Pragmatically, these costs can be fairly divided among classes based on a measure of usage or even revenue since there is not necessarily a link between system cost drivers and these costs.

The first task in choosing a cost allocation method is to ascertain the objective of the study: Is it focused on short-run

Many factors influence cost allocation method selection

The appropriate choice of a detailed allocation approach and the most appropriate method may be affected by such factors as:

- Are the utility's loads growing, shrinking or stagnant?
- Does the utility have a mix of different types of supply resources to serve varying load levels?
- Does the utility rely on transmission facilities to deliver power from remote baseload, hydro or renewable energy resources?
- Is generation mostly spread among load centers, or is supply concentrated within certain portions of the service territory?
- Does the utility's supply mix include variable renewable resources, such as wind and solar?
- Does the utility have sufficient load density to support the distribution system with energy sales, or is the load so sparse that other revenues are required to pay for distribution (as is the case for some cooperatives)?
- Are peaking resources located inside the service territory near loads, or are they dependent on transmission from distant sources?
- How do the utility's customers break down into classes and subclasses that have significantly different cost characteristics?
- Does the utility have reasonably reliable hourly load data, by class?
- Does the utility have demand response resources that can help meet extreme peak requirements?
- Does the utility have storage resources that can shift generation or loads among time periods?
- Does the utility's load peak in the winter, in the summer or both?
- Do different customer classes peak at different times of the day or different seasons of the year?

Each of these questions bears on the most appropriate cost allocation approach. A mix of resources requires a method that appropriately treats that variety of resources differently in classification and allocation. Variable resources require a method that assigns their costs to the hours in which they produce benefits. The location of supply resources determines whether the method must apportion transmission costs among multiple purposes.

81 Bonbright described some distribution costs as strictly unallocable: "But if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs for the reason just given, while it is also denied a place among the customer costs for the reason stated previously, to which cost function does it then belong? The only defensible answer, in my opinion, is that it belongs to none of them. Instead, it should be recognized as a strictly unallocable portion of total costs. And this is the disposition that it would probably receive in an estimate of long-run marginal costs" (1961, p. 348). The same "unallocable" characteristic may apply to other system costs in an evolving industry.

equity considerations or rather on efficiency considerations? Is the system an optimal system or a suboptimal system for today's needs? Most advocates of using embedded cost studies point to the direct link with the revenue requirement and spreading that revenue requirement among multiple customers. Although there is a wide range of embedded cost methods, all of them apportion the existing revenue requirement, and rates based on the results should produce the allowed amount of total revenue.

Within this broad sense of equity, however, the methods selected may result in vastly different results. For example, in one docket, the Washington Utilities and Transportation Commission considered the results of several approaches to embedded cost of service studies, presented by the utility, the commission staff and intervenors. The commission did not rigorously follow any of them but found that the range of these studies defined an appropriate range in which the revenue allocation should be based.

Another goal of cost allocation is long-run efficiency to guide consumer consumption based on where costs are going, not where they are.[82] The use of long-run marginal costs attempts to do this in the cost allocation phase of rate-making, and indeed this was the position that some advocates took in the hearing era after passage of PURPA. Their position was that all costs should be forward-looking to encourage long-run efficiency and that past costs cannot be "saved," so there is no point using them for cost allocation or rate design.

But marginal costs are not the same as current costs making up the revenue requirement, and some method is needed to reconcile (up or down) the results of a marginal cost study with the revenue requirement. The methods to do this include proportionality (adjusting all class revenue requirements by the same percentage) and various methods of focusing on certain aspects of cost in adjusting allowed revenues in consideration of marginal cost. These methods have been highly controversial, as discussed in detail in Part III.

In the short run, it is desirable to optimize the incurrence of variable costs such as fuel, labor and purchased energy. Consideration of short-run marginal costs focuses on exactly this. If systems have excess generating capacity, power costs are low; with deficient capacity (or fuel or water shortages), power costs are high. One problem with establishing cost allocation on the basis of short-run marginal costs is that few costs other than power supply vary significantly in the short run. Although utilities do reduce staffing during a recession and may defer maintenance, these are minor cost savings. Therefore, the costs considered are only a very small fraction of the revenue requirement.

During periods of energy shortage, such as the California energy crisis of 2000-2001, regulators may believe that short-term deviations from traditionally used long-run marginal cost theory are appropriate. In California's case, the commission approved both higher thresholds for energy efficiency investments and very sharply increased tailblock rates.

One issue that has been raised with respect to various short-run and NERA-style marginal cost studies is that they capture only a limited window in time, when utility resources may be imperfectly matched to utility customer needs. This is discussed in detail in Part IV.

A market that has short-run marginal costs that are equal to long-run marginal costs is said to be in equilibrium. When in equilibrium, the cost of producing one more unit of output with existing resources is relatively expensive, because all of the low-cost resources are already fully deployed, resulting in short-run costs that exactly match the cost of building and operating new resources. For electric generation, this might mean running a peaker to provide energy in many hours because available lower-cost units are fully deployed. In this situation, there would be no difference between marginal cost studies using different time horizons.

But electric utilities are almost never in equilibrium, for several reasons:

- Forecast and actual loads, costs, technologies and resource availability change faster than the system can be reconfigured, leaving systems with capacity excess or deficiency and resources that are poorly suited to current needs.
- Utilities maintain reserve margins for reliability, which often results in energy dispatch costs that are lower than

82 Canadian hockey great Wayne Gretzky is widely quoted as having said: "I skate to where the puck is going to be, not where it has been."

the fixed and variable costs of a new efficient generating unit. A system with marginal running costs high enough to justify new construction will tend to have a relatively low reserve margin.

- In other markets, short-run costs can be allowed to rise, with the tightening available supply rationed by pricing, and the short-run cost becomes the price of outbidding other users. For electricity, that approach would lead to blackouts.
- Transmission and distribution do not have short-run marginal costs comparable to the long-run costs of new equipment. Short of allowing overloads until lines and transformers fail, there is no way to bring a T&D system into equilibrium.
- As energy generation transitions from fossil generation with high running costs to zero-carbon resources with low running costs and high capital costs, it will be harder to match short-run and long-run costs.

A state of disequilibrium can severely affect some customer classes if a marginal cost study is based on short- to medium-term costs. If a shortage of power supply exists, it will severely affect large-volume customer classes; if a surplus exists, it will severely affect residential and small commercial customers.

In the following chapters, we address in detail how each type of cost should be considered in different approaches to cost allocation. The methods will be different for every utility because every utility has a different history and a different mix of resources, loads, costs, issues and opportunities. The appropriate method for each utility may be slightly different. It is driven by the mix of customers, the nature of the service territory, the type of resources employed and the underlying history that guided the evolution of the system. No single method is appropriate for every utility, and no single method is likely to produce a noncontroversial result. Many regulators will seek consistent methods to be applied to all utilities in their state, which may require compromise from the most appropriate method for each individual utility. In Chapter 27, we discuss how regulators can use the results of quantitative cost studies to actually determine a fair allocation of costs among classes.

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Part III:
Embedded Cost of Service Studies

9. Generation in Embedded Cost of Service Studies

This chapter addresses the allocation of generation costs, including investment-related costs, operation and maintenance costs and fuel costs. As noted in Section 6.1, equivalent changes in the allocation of a cost category among classes can be achieved by changing functionalization, classification or the choice of allocation factor.[83] That section discusses the relevant issues at a high level, and this chapter delves more deeply into the underlying concepts and analytical techniques.

This chapter is not generally relevant to cost allocation for utilities that have restructured and no longer procure generation resources, as long as the generation prices suppliers offer (directly to customers or to the utility for default service) are differentiated by rate class. High-level cost allocation issues with respect to generation and default service are discussed in Section 7.2.

As discussed in Chapter 3, utilities acquire and maintain different types of generation resources, with distinct operating capabilities, to meet a range of needs including low-cost energy, reliability, **load following** and environmental compliance. Different classification and allocation methods may be necessary to equitably allocate the costs of different types of generation resources. In more recent years, energy efficiency, expanded demand response, distributed generation and energy storage — all of which can be located where load relief is most valuable — have expanded the utility's options to meet load growth or reduce demands on aging assets without building transmission, distribution or central generation facilities.

Fuel costs, purchased power and dispatch O&M costs, such as the short-run variable cost of pollution controls, are typically classified as energy-related. The other categories of generation costs have generally been classified as being driven by some combination of energy (total energy requirements to serve customers, plus losses) and demand (some measure of loads in the hours that contribute to concerns about the adequacy of generation supply to meet loads). Energy use is sometimes broken into TOU periods, so that different types of costs are spread over the hours in which they are used, as discussed further in Section 9.2 and Chapter 17.

When there are multiple cost-based approaches for estimating a classification or allocation factor, a compromise among the results may be appropriate. For example, various measures of reliability risk (emergency purchases, operation of peakers, interruption of load, inadequate operating reserve) may be distributed differently across the months, and the regulator may reasonably select a generation demand allocator averaging across the results of those measures. Similar conditions might apply for varying estimates of the firm-capacity equivalent for wind plants or other inputs.

Some cost of service studies identify other classifications of generation costs, such as ancillary services. These components are generally very small compared with total generation costs, and some ancillary services (automatic generation control, black start capability, uplift) can be difficult to relate to class load characteristics.

9.1 Identifying and Classifying Energy-Related Generation Costs

Many regulators have recognized that energy needs are a significant driver of generation capital investments and nondispatch O&M costs. In modern utility systems, generation facilities are built both to serve demand (i.e., to meet capacity and reliability requirements) and to produce energy economically. The amount of capacity is largely determined by reliability considerations, but the selection of generation technologies and thus the cost of the capacity are

83 As mentioned previously, the third step is usually called allocation, which is the same as the name of the entire process. Some analysts refer to this third step as factor allocation in an attempt to prevent confusion.

largely determined by energy requirements.[84] For variable renewables, particularly wind and solar, the effective capacity (in terms of the reliability contribution) of the generators is much smaller than their nameplate capacity, and the costs are mostly undertaken to provide energy without fuel costs or air emissions. Energy storage systems provide both energy benefits (by shifting energy from low-cost to high-cost hours) and reliability benefits, while demand response is used primarily to increase reliability.

As discussed in the text box on pages 78-79, some older cost of service studies classified a wide range of capital and nondispatch O&M costs as demand-related on the grounds that the costs were in some manner fixed, without regard for cost causation. This approach, known as **straight fixed/variable**, is anachronistic and does not reflect cost causation.[85]

Table 12 shows the capital and O&M costs estimated for new conventional generation units from the 2018 Lazard's *Levelized Cost of Energy Analysis* report.[86] Although the original costs and current plant in service and O&M costs of older units will vary, the general relationships have been consistent.

This section first discusses the insights on this issue from competitive wholesale markets. This is followed by four different classification approaches and two joint classification and allocation approaches, then a discussion of other technologies and issues.

Table 12. Cost components of conventional generation, 2018 midpoint estimates

Technology	Capital cost (per kW)	Fixed operations and maintenance (per kW-year)	Variable operations and maintenance (per MWh)
Combustion turbine	$825	$12.50	$7.40
Combined cycle	$1,000	$5.75	$2.80
Coal	$3,000	$40.00	$2.00
Nuclear	$9,375	$125.00	$0.80

Source: Lazard. (2018). *Lazard's Levelized Cost of Energy Analysis — Version 12.0*

9.1.1 Insights and Approaches From Competitive Wholesale Markets

The ISOs/RTOs that operate energy (and in some cases, capacity) markets — specifically ISO-NE, NYISO, PJM, ERCOT, MISO and the SPP — provide examples of how the recovery of capital investment and nondispatch O&M costs naturally splits between energy and demand. The pricing in these markets can provide both a **competitive proxy** for classifying generation costs and a benchmark to check the reasonableness of other techniques.

ERCOT has no capacity market, and all costs are recovered through time-varying energy charges. Those energy charges are heavily weighted toward a small number of hours, which do not tend to have particularly high loads; the highest-load hours are not the highest-cost hours. Figure 30 on the next page shows the hourly load and Houston Hub prices for 2017 (Electric Reliability Council of Texas, 2018, for load data; ENGIE Resources, n.d., for pricing data).

Prices generally trend upward with load, but the highest-priced hours are spread nearly evenly across load levels.

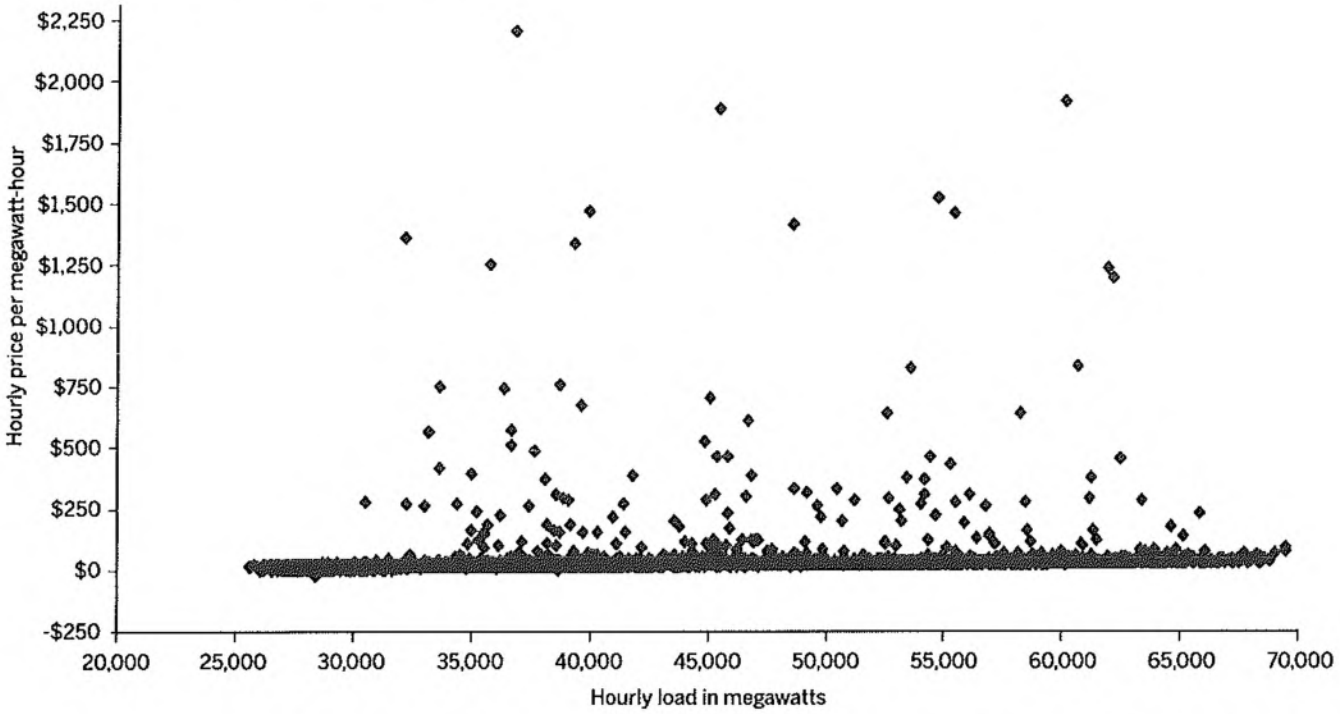
In 2017, the highest-priced 1% of hours (with prices over $160 per MWh) would have provided 18% of the annual net margin for a baseload plant with no variable cost, 53% of the margin for a plant with a variable cost of $20 per MWh (perhaps a combined cycle unit), and 77% of the margin for a plant with a $30-per-MWh variable cost (such as a recently built combustion turbine), assuming ideal dispatch and no

84 "Citing both past operating experience and future resource planning, the Division [the PSC intervention staff] notes that resources with higher energy availability are chosen over those with lower energy availability. Since energy plays a role in the selection of least-cost resources, the Division concludes that some weight needs to be given to energy in planning for new capacity, and the current weight of 25 percent is reasonable. We find the qualitative argument offered by the Division to be ... convincing." (Utah Public Service Commission, 1999, p. 82). See also Washington Utilities and Transportation Commission (1993, pp. 8-9).

85 The term "straight fixed/variable" is imported from FERC's rate design method for wholesale gas supply, where utilities, marketers and very large customers contract for capacity in a portfolio of individual pipeline and storage facilities. As is true for many electric wholesale purchased power contracts, these gas contracts require that the buyers pay for investment-related costs regardless of how they use the resources and pay for variable costs in proportion to their usage. This approach is workable at the wholesale level but is not applicable to retail cost allocation, where the utility bundles a portfolio of generation assets for all of its customers.

86 The coal cost in the table is Lazard's low end, since the high-end cost "incorporates 90% carbon capture and compression" (Lazard, 2018, p. 2), which is in use on only one existing utility coal unit, SaskPower's Boundary Dam. The $3,000/kW value is also consistent with the costs of the last three coal plants completed by U.S. regulated utilities (Turk, Virginia City and Rogers/Cliffside 6, all completed in 2012). Actual current costs of various vintages of resources will vary for each utility.

Figure 30. ERCOT load and real-time prices in 2017



Sources: Electric Reliability Council of Texas. (2018). *2017 ERCOT Hourly Load Data*; ENGIE Resources. *Historical Data Reports*

outages. Those 88 hours representing the costliest 1% occurred in every month and almost the whole range of annual loads.

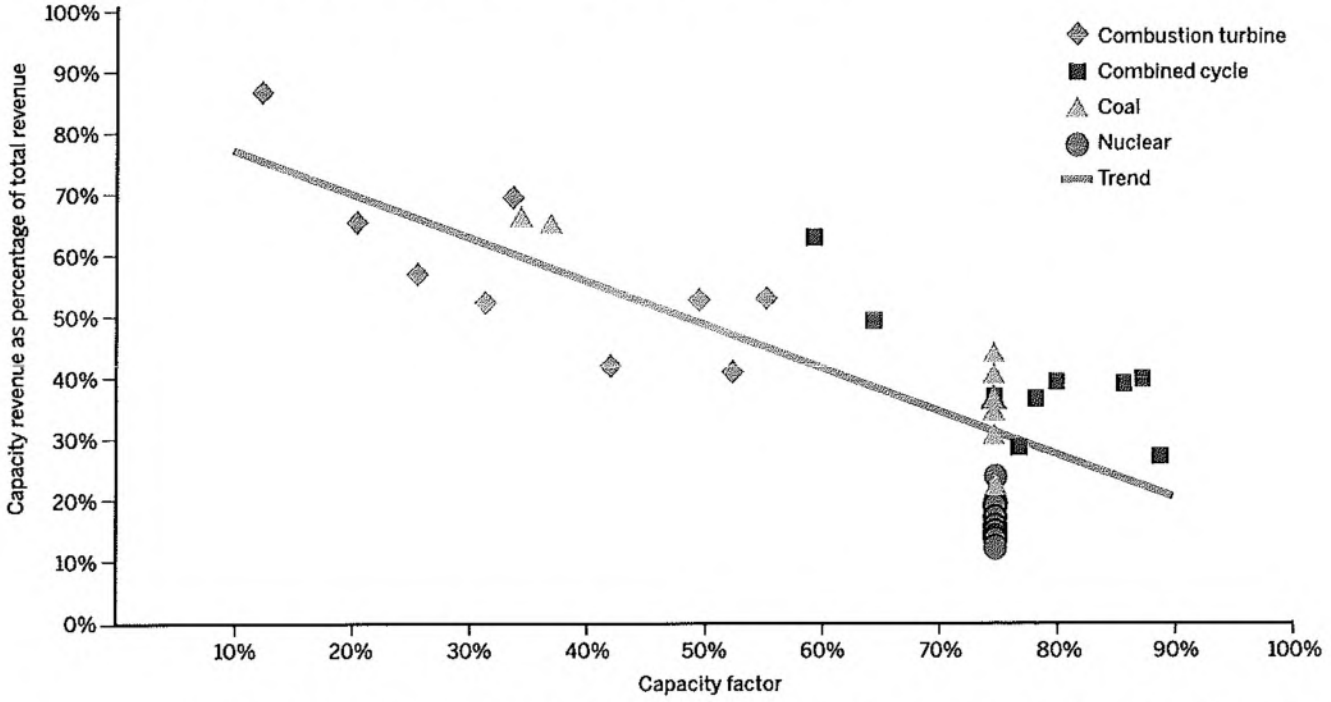
In contrast, the 1% of highest-load hours would have provided 5.1% of the margin for the baseload plant, 2.4% for the intermediate plant and 2% for the combustion turbine. This cost pattern suggests that, at least in some systems, generation costs should be time-differentiated but that load is not a good proxy for the highest-price periods. Classes with the ability to shape load to low-cost periods (with demand response or storage) may be much less expensive to serve than those with inflexible load patterns.

Regardless of how the top hours are chosen, the ERCOT data indicate that most of the long-term power supply costs are not recovered from the few peak hours and thus should not be considered demand-related. For a load shaped like the ERCOT average load, only about 3% of the generation costs were associated with the 1% of highest-load hours, and about 20% were associated with the 1% of highest-price hours.

In New England, the ISO-NE external market monitor estimated that the net revenues available to pay the capital investment and nondispatch O&M costs of a typical recently built gas combined cycle unit would have been about 25% to 60% from the energy market and the remainder from the capacity market, depending on the year (Patton, LeeVanSchaick and Chen, 2017, p. 13). The comparable values for nuclear units were almost all from the energy market (Patton et al., 2017, p. 17).

The PJM independent market monitor reports the capacity revenues and the net energy revenues (i.e., energy revenue in excess of fuel and variable O&M) for a variety of plant types (Monitoring Analytics, 2014, pp. 219-222, 2019, pp. 335-339). These are the revenues available to pay for the capital investment and nondispatch O&M costs and thus represent the market allocation of these costs for the plants. Figure 31 on the next page shows the portion of these costs recovered through capacity payments for four types of new plants (gas-fired combustion turbine and combined cycle units, and hypothetical new coal and nuclear) in each year

Figure 31. Capacity revenue percentage in relation to capacity factor in PJM



Data sources: Monitoring Analytics. (2014 and 2019). *2013 State of the Market Report for PJM, 2018 State of the Market Report for PJM*

2009 through 2017 (Monitoring Analytics, 2014, 2019).[87]

The concept displayed here is that units with a high **capacity factor** tend to make more of their revenue from energy markets instead of from the capacity market. In this set of PJM data, energy revenues cover 14% to 60% of the combustion turbine costs, 38% to 74% of combined cycle costs, 56% to 73% of baseload coal plant costs, about 34% of the costs of economically dispatched coal units, and 77% to 89% of nuclear costs over the nine-year period. The values for 2017 were 39% for modern combustion turbines, 87% for combined cycle units, 65% for coal and 20% for nuclear. Current values for PJM or the relevant load zones could be used as the demand classification percentages for vertically integrated utilities in PJM (e.g., IOUs in Kentucky, Virginia and West Virginia, and municipal and cooperative utilities in several states).

The market monitoring unit of the NYISO provided similar analyses for the various pricing zones of that RTO, as shown in Table 13 (Patton, LeeVanSchaick, Chen and Palavadi Naga, 2018, Table A-14, with additional calculations by the authors). The upstate zones have relatively low capacity prices, while the Hudson Valley and New York City have very high capacity prices, and Long Island has intermediate prices. Both capacity and energy revenues vary among zones within each of these three areas, between load pockets within zones and among combustion turbine types.

Table 13. Energy portion of 2017 net revenue for New York ISO

Zone	Generator type		
	Combustion turbines	Combined cycle	Steam
Upstate	72% to 80%	71% to 79%	42% to 55%
Long Island	52% to 70%	62% to 76%	21% to 57%
Hudson Valley and New York City	31% to 49%	34% to 55%	6% to 29%

Sources: Patton, D., LeeVanSchaick, P., Chen, J., and Palavadi Naga, R. (2018). *2017 State of the Market Report for the New York ISO Markets;* additional calculations by the authors

87 The independent market monitor assumed that a nuclear plant would operate at a 75% capacity factor and made the same assumption for the coal plant through 2015; the capacity factors for the gas-fired plants and for coal in 2016 and 2017 are determined from the economic operation of the units.

9.1.2 Classification Approaches

Many utilities and regulators acknowledge that a large portion of generation investment and nondispatch O&M costs is incurred to serve energy requirements. There are two categories of methods to classifying these costs as energy-related and demand-related. First, average-and-peak is a top-down approach that uses high-level data on system loads and costs. Second, there is a range of bottom-up approaches that examine the drivers for costs on a plant-specific basis:

- Base-peak and related methods.
- Equivalent peaker method.
- **Operational characteristics methods.**

As a general matter, the bottom-up approaches are preferable for classifying generation costs. The average-and-peak approach is well suited for shared distribution system costs, as discussed in Section 11.2.

Average-and-Peak Method

The average-and-peak approach can be applied in classification, when classifying a portion of costs as energy-related and the remainder as demand-related, or in developing a generation capacity allocator that reflects both energy and demand. When using this approach as a classification method, the **system load factor** percentage is classified as energy-related and the remainder as demand-related.[88] When used as an allocation factor, the average-and-peak factor for each class is:[89]

$$\frac{A_C}{A_S} \times SLF + \frac{P_C}{P_S} \times [1\text{-}SLF]$$

Where A = annual average load = energy ÷ 8,760

P = peak load

C = class

S = system

SLF = system load factor = (annual energy) ÷ (peak load × 8,760)

The system load factor, and hence the average-and-peak approach more generally, varies over time independent of the mix of the utility's generation resources and does not respond to changes in that mix unless those changes are accompanied by retail pricing that follows the cost structure.

In addition to changing as loads change, the average-and-peak approach ignores the mix of resources and costs. This approach would produce the same classification of plant for a system that was entirely composed of gas-fired combustion turbines (with low capital costs and high fuel costs) or of coal-fired plants (with high capital costs to produce lower fuel costs).

Thus, while the average-and-peak method for generation costs may sometimes fall in the range of reasonable results, it is neither logical nor consistent.

Base-Peak Methods

Various utilities and other analysts have proposed to subfunctionalize generation resources (in the simplest case, between baseload and peaking plants) and classify each category of generation in a different manner. For example, peakers may be classified 100% as demand-related, while baseload resources are classified 75% to demand and 25% to energy, or some other location- and situation-specific ratio.

More advanced analyses have subfunctionalized generation among base, intermediate and peak categories, known as BIP classification. The base generation might be defined as all nuclear and coal plants, with the intermediate being gas-fired steam and combined cycle plants and the peak units being combustion turbines, storage and demand response. Alternatively, base plants might be any unit that operated at more than a certain capacity factor (for example, 60%), peakers those that ran at less than 5%, and intermediate anything between those 5% and 60% capacity factors. Or, rather than using capacity factor (which can be low due to forced outages, maintenance or economic dispatch), the

88 This method is sometimes called the system load factor approach. It has also been called "average and excess" because a fraction of cost equal to the system load factor is allocated on energy and the excess of costs on a measure of peak loads (Coyle, 1982, pp. 51-52).

89 This average-and-peak allocator should not be confused with the average-and-excess demand allocator described in the 1992 NARUC *Electric Utility Cost Allocation Manual*, which allocates a portion of costs in proportion to average load and the excess in proportion to each class's excess of peak load over its average use. That legacy average-and-excess allocator is essentially just a peak allocator (Meyer, 1981).

generation classes can be defined using operating factor (the ratio of output to equivalent availability). At an extreme, each generation type, or even each unit, can be classified separately.

While the base-peak classification approach and related methods are highly flexible, that is both their greatest strength and a great weakness. The strength is that the method can be modified to accommodate the diversity of generation resources; the weakness is that the method requires a set of decisions about the definition of the generation classes and the classification percentage for each class. The base-peak method is connected to actual utility planning only at the highest conceptual level and provides limited guidance for the nitty-gritty details of traditional classification.

One of the challenges of the base-peak approach relates to the changing usage of generation resources. For example, several units that were built to burn coal in baseload operation have been converted to burn natural gas and thus run mostly on high-load summer days.[90] These units operate as peak or intermediate resources (depending on the definitions used in the particular analysis), but most of the capital costs are attributable to the original baseload design. This problem may be ameliorated by removing those additional costs from the base-peak or BIP computation and directly classifying them as energy-related.

Recent technological changes pose additional challenges and opportunities for expanding the base-peak approach from two generation profiles, or the three profiles of the BIP method, to a full analysis of the use of generation resources. Decades ago, it was reasonably accurate to treat generation resources as being stacked neatly under the load duration curve in order of variable costs. The growing role of variable output renewable resources, additional storage and economic demand response reduces the accuracy of those simple models. Resources like wind and solar do not fit neatly into the BIP categories, providing service in distinct time patterns that may not be related to system loads. At the same time, many utilities have access to much more granular detail on hourly consumption by customer.[91] The BIP method can be expanded to reflect conditions (output by several classes of conventional generation, solar, wind and storage; energy use for storage; usage by class) in as many time periods (or load levels, or bins combining consumption and generation conditions) as desired, even down to an hourly allocation method. Usage and hence costs could thus be assigned directly to the classes using power at the times that each resource provides service.[92]

Equivalent Peaker Method

The equivalent peaker method,[93] discussed at length in the 1992 NARUC *Electric Utility Cost Allocation Manual,* attributes as demand-related the portion of investment in each resource that would have been incurred to secure a peaking resource, such as demand response or a combustion turbine.[94] Peaking resources are usually treated as 100% demand-related, while intermediate and baseload plants are classified as partly energy and partly demand.

If only peak load had been higher (and other needs were already satisfied) in the years in which the utility made the bulk of its generation construction decisions, it would have likely met that increased load by adding peaker capacity.[95] Utilities historically have justified building baseload capacity by relying on these plants' long hours of use and lower fuel

90 Some coal plants that once ran as baseload resources have been taken out of service in low-load months to reduce O&M costs. This includes Nova Scotia Power's Lingan 1 and 2 (Barrett, 2012), Luminant's Monticello and Martin Lake (Henry, 2012) and the Texas Municipal Power Agency's Gibbons Creek (Institute for Energy Economics and Financial Analysis, 2019).

91 Most utilities have long known the hourly generation by unit.

92 Some utilities refer to their classification method as BIP, even though it does not reflect the differences in costs among the various types of generation. For example, the Louisville Gas & Electric and Kentucky Utilities 2018 "BIP" computation classified nondispatch generation costs this way: 34% (the ratio of minimum to peak load) to energy; 36% (the 90% ratio of winter peak to summer peak, minus the 34% energy allocation, or 56%, times the 65% of the peak-period hours that occur in winter) to the winter peak demand; and the remaining 30% to the summer peak demand (Seelye, 2016, Exhibit WSS-11). This approach has no cost basis.

93 In some jurisdictions, this is called the peak credit method.

94 This approach is sketched out in Johnson (1980, pp. 33-35) and described in more detail in Chernick and Meyer (1982, pp. 47-65).

95 To some extent, the peakier load would likely allow for development of more demand response and load management. Estimating the potential and costs for these resources under hypothetical load shapes may be difficult.

costs.[96] This incremental capital cost (often called capitalized energy or "steel for fuel") is attributable to energy requirements, not demand. The investment-related costs of baseload resources above and beyond the cost of peaking units are incurred to serve energy load, not demand. Treating these costs as demand-related overstates the cost of meeting demand and understates the costs incurred to meet energy requirements. This phenomenon has been understood since the 1970s and 1980s:

> [T]he extra costs of a coal plant beyond the cost necessary to build a combustion turbine should all be allocated [on] energy. The rationale for this allocation is that the marginal cost of capacity in the long run is just the lowest-cost technology required to meet peak load, which is typically a combustion turbine. Choosing to invest beyond this level [of combustion turbine capital cost] is justified not on capacity grounds, but on energy grounds. That is, the extra capital cost of a coal plant allows the utility to use a low-cost fuel and avoid higher-cost fuels (Kahn, 1988).

However, there are several additional issues with this concept in the modern electric system. First, the method does not adapt well to wind and solar, where the capital investment is primarily justified by avoiding fuel costs but the installed capital cost per nameplate MW may be little different from the cost of a peaker. An intermediate or baseload plant that is not much more expensive than a contemporaneous peaking resource would be classified as mostly demand-related, while very expensive plants are classified as mostly energy-related. And often, peaker units are used to provide energy when baseload units are not operating or to provide power for off-system sales.[97]

Under the equivalent peaker method, the demand- or reliability-related portion of the cost of each generation unit is estimated as the cost per kW of a peaker (usually a simple-cycle combustion turbine) installed in the same period, times the effective capacity of that unit, adjusted for the equivalent availability of a peaker.[98] The cost of the unit in excess of the equivalent gas turbine capacity is energy-related.

However, the simple version of this calculation typically will overstate the reliability-related portion of plant cost because it assumes a steam plant supports as much firm demand as would the same capacity of (smaller) combustion turbines. Due to higher forced outage rates, lengthy maintenance shutdowns and the size of units, a kilowatt of steam plant capacity typically supports less firm load than a kilowatt of capacity from a small peaker. A system with a peak load of about 6,500 MWs and a 65% load factor could achieve the same level of reliability with 80 units of 100 MWs (8,000 MWs, or a 23% reserve) or 19 units of 600 MWs (11,400 MWs, or a 75% reserve), assuming the units all have a 6% **equivalent forced outage rate** and that the load shape can accommodate all required maintenance off-peak. Increasing the equivalent forced outage rate to 10% would increase the required reserve for the 100-MW units to about 40% and for the 600-MW units to 90%. Even with the 6% equivalent forced outage rate, if the load factor were 96%, the reserve requirement would rise to 30% with 100-MW units and 90% with 600-MW units.

Figure 32 on the next page shows the gross plant per kW for combustion turbines as of 2011, from FERC Form 1 data (Federal Energy Regulatory Commission, n.d.). These values include the original cost of the units, plus capital additions since the plants entered service, minus the cost of any equipment retired. This tabulation includes all non-CHP simple-cycle combustion turbines for which cost data were available.[99] Some of the later combustion turbines in this sample may not be pure peakers, since manufacturers

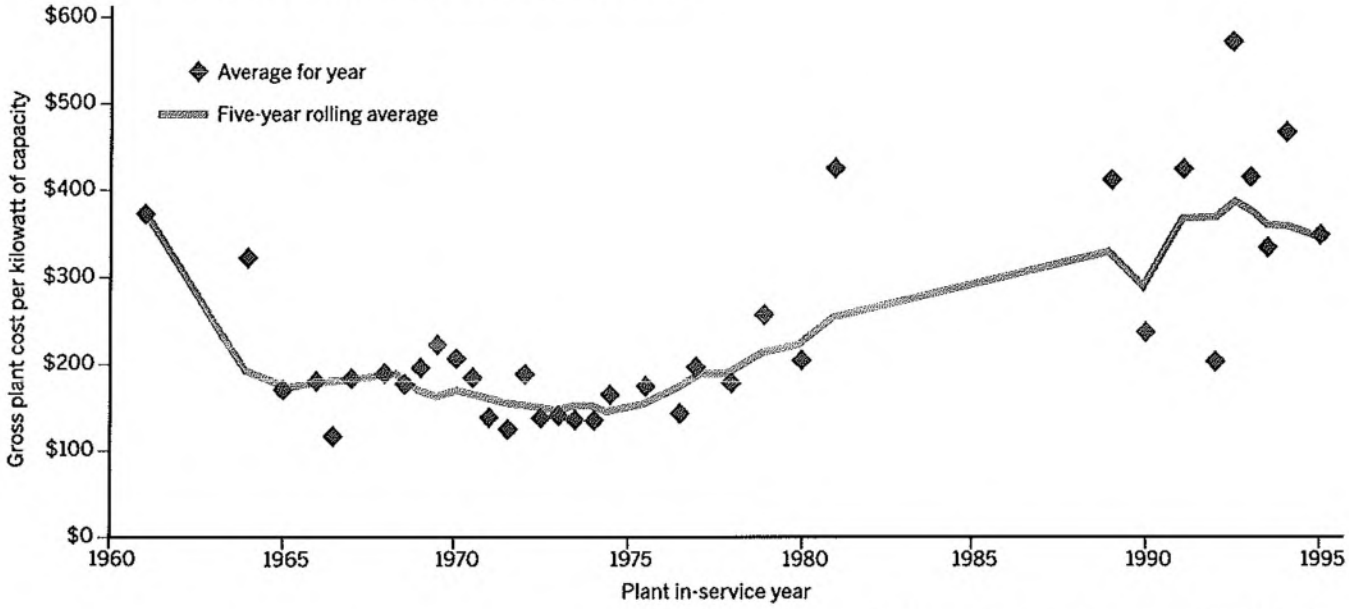
96 Similar reasoning applies to the decision to add renewable resources, substituting investment for fuel costs. See footnote 120.

97 During the 2000-2001 California energy crisis, oil-fired peakers in the Pacific Northwest operated at high monthly capacity factors because they were exempt from both gas supply constraints and California emissions regulations. U.S. Energy Information Administration Form 906 for 2000 and 2001 demonstrates the incremental oil burn in 2000 and 2001, particularly for Puget Sound Energy.

98 In the future, the reference peaking capacity might be an increase in demand response cost or storage peak output capacity, without an increase in energy generating capability. The reference peaker should always be the least-cost option for providing reliability.

99 Municipal and cooperative utilities and non-utility generators (both those under contract with utilities and those operating in the merchant markets) do not file FERC Form 1 reports, so their units are not included in this analysis. The municipal and cooperative utilities typically retain financial and operating records that are compatible with the FERC system of accounts, allowing comparison of the data for a specific utility's nonpeaking resources with national data on contemporaneous peaker costs.

Figure 32. Cost of combustion turbine plant in service in 2011



Data source: Federal Energy Regulatory Commission Form 1 database

developed more expensive and more efficient designs, including steam injection.

For comparison, coal plants built in this period generally cost from several hundred dollars per kW to more than $2,000 per kW; the latest vintage coal plants cost as much as $3,000 per kW. Steam plants fired by gas and oil (and not converted from coal) tend to have a wide range of gross plant costs, from the prices of contemporaneous combustion turbines to perhaps twice those costs. Nuclear plants generally have gross plant costs well above $1,000 per kW, up to $8,000 per kW. Combined cycle plants have usually been 20% to 50% more expensive than contemporaneous combustion turbines.[100]

The capital costs of various types of generating capacity can be compared with the costs of peakers in several ways, including the following:

- Comparing recent or current gross plant costs for other generators with the corresponding cost of peakers, as discussed above.
- Comparing recent or current net plant (gross plant minus accumulated depreciation) costs for nonpeaking generators with the corresponding net plant costs of contemporaneous peakers. This comparison is theoretically the most appropriate basis for classifying generation rate base, which is based on net plant. Unfortunately, net plant is not generally publicly reported by plant or unit, so most cost analysts will have a difficult time implementing this approach. In addition, many utilities have depreciated peakers at a faster rate than steam plants, resulting in lower net plant for a peaker than for a steam plant with the same initial cost, additions and retirements. This results in a higher percentage of the steam plant costs being classified as energy-related based on net plant than gross plant. It is not obvious whether the additional classification to energy is more equitable than the result of the gross plant allocation.
- Comparing the cost of building the actual mix of generation today with the cost of building a peaking-only system today.[101] This approach avoids the problem of

100 These cost ratios are provided to explain the importance of identifying the demand-related portion of generation investment. Any application of the equivalent peaker method should compare the costs of the utility's existing plants to the costs of contemporaneous peakers, using the most comparable estimates of the costs of peakers, reflecting geographical and other differences.

101 The peaking-only system might include combustion turbines, demand response and storage resources.