costs; the data are 2017 numbers from FERC Form 1, Page 402, for Northern States Power Co.-Minnesota (Federal Energy Regulatory Commission, n.d.).

Table 16 does not include the company's wind resources, which average about $30 per kW-year in O&M, since MISO credits wind with unforced capacity value at only about 15% of rated capacity, or about 17% of the value of an installed MW of typical conventional generation. The demand-related portion of the wind capacity is thus less than $1 per kW-year, and the wind O&M is almost all energy-related.[104]

Operational Characteristics Methods

The operational characteristics methods classify generation resources (units, resource types, purchases) based on their capacity factors or operating factors. Newfoundland Hydro classifies as energy-related a portion of the cost of each oil-fueled steam plant equal to the plant's capacity factor (Parmesano, Rankin, Nieto and Irastorza, 2004, p. 22). At first blush, this approach appears to roughly follow the use of the resource, with plants that are used rarely being treated as primarily demand-related and those used in most hours classified as predominantly energy-related. Unfortunately, the use of capacity factor effectively classifies more of the cost to demand as the reliability of the resource declines.

A better approach would be to use the resource's operating factor, which is the ratio of its output to its equivalent availability (that is, its potential output, if it were used whenever available). This approach would classify any resource that is dispatched whenever it is available (e.g., nuclear, wind and solar) as essentially 100% energy-related. That may be seen as an overstatement, since those resources generally provide some demand-related benefits and are sometimes built to increase generation reliability, as well as to produce energy with little or no fuel cost.

9.1.3 Joint Classification and Allocation Methods

Although most cost of service studies classify capital investments and capacity-related O&M as either demand-related or energy-related, classify power and short-term variable costs as energy-related, and then allocate energy-related and demand-related costs in separate steps, two approaches accomplish both at once. These are the probability-of-dispatch (POD) and **decomposition** approaches.

Probability of Dispatch

The POD approach is the better of the two.[105] Methods using this approach are generically referred to as probability of dispatch, even for versions that do not explicitly incorporate probability computations.[106] A simplified illustrative example of power plant dispatch is shown in Figure 33 on the next page, under the utility load duration curve. The example uses only four types of generation: nuclear, coal, gas combined cycle and a peaking resource consisting of a mix of demand response, storage and combustion turbines. An actual POD analysis might break the generation data down to the plant or even unit level and may need to include load management and demand response as resources. This simplified example also does not illustrate maintenance, forced outages or ramping constraints.

Off-system sales and purchases can be added or subtracted from the load duration curve when they occur, or they can be subtracted or added to the generation available in each hour or period. Similar adjustments may be needed to reflect the charging of storage and operation of behind-the-meter generation.

Figure 34 shows the composition of demand in each hour for the same illustrative system, divided among three customer classes. In this example, the residential class peak load occurs when load is high but not near the system peak.

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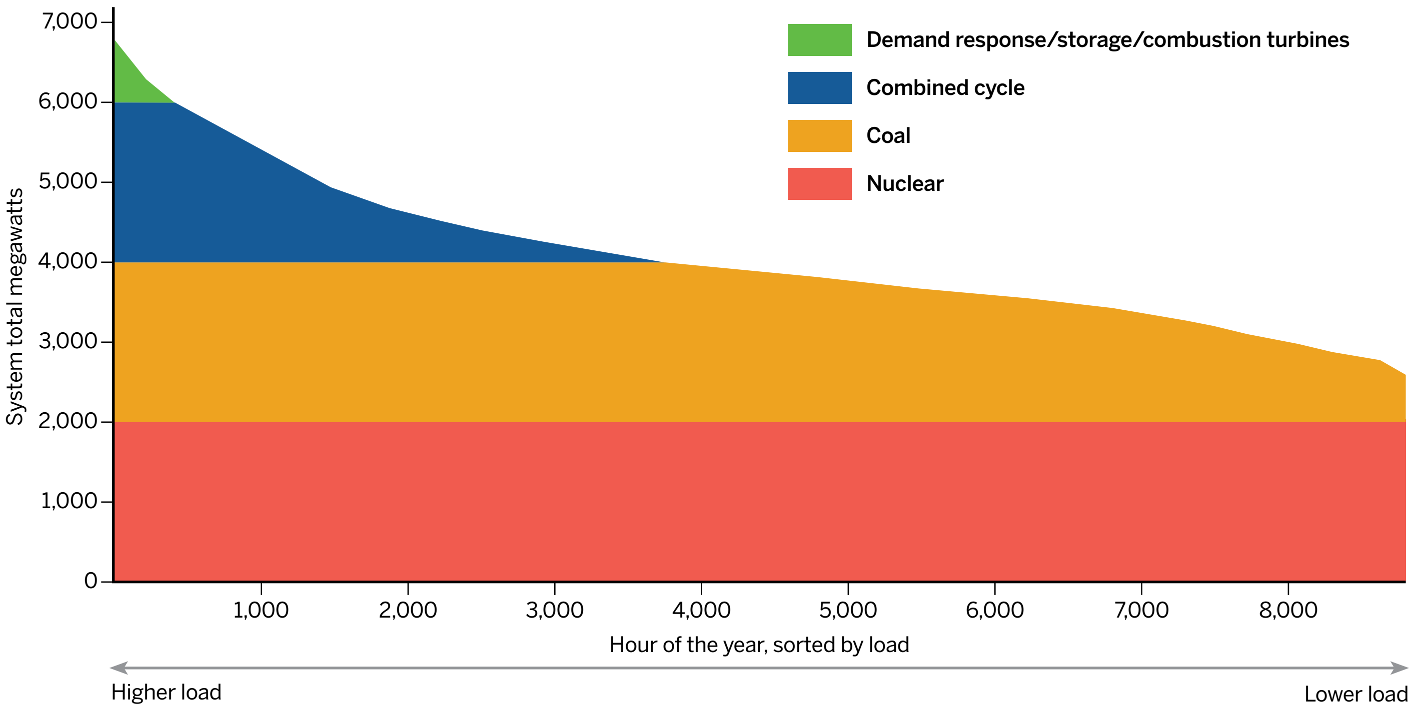
104 The nonfuel O&M costs per kW for Northern States Power's two small waste-burning plants and its small run-of-river hydro plant are even higher than the nuclear O&M and hence are effectively entirely energy-related, even if the hydro plant provides firm capacity.

105 The Massachusetts Department of Public Utilities explained its preference for this method as follows: "The modified peaker POD results in a fair allocation of embedded capacity costs because this method recognizes the factors that cause the utility to incur power plant capital costs and because this method allocates to the beneficiaries of fuel savings the capitalized energy costs that produce those savings" (1989, p. 113).

106 For an example of the POD method, see La Capra (1992).

Figure 33. Simplified generation dispatch duration illustrative example



This situation might arise for a winter-peaking residential class in a summer-peaking system, or an evening-peaking residential class in a midday-peaking system.

Note that the three customer classes need not peak at the same time. On a high-load summer day, the primary industrial class might peak in the morning, the secondary commercial class at 1 p.m., and the residential class in the evening. Large commercial buildings typically experience their peak load in the summer, since large buildings require cooling in most climates. If a large percentage of home

Figure 34. Illustrative customer class load in each hour

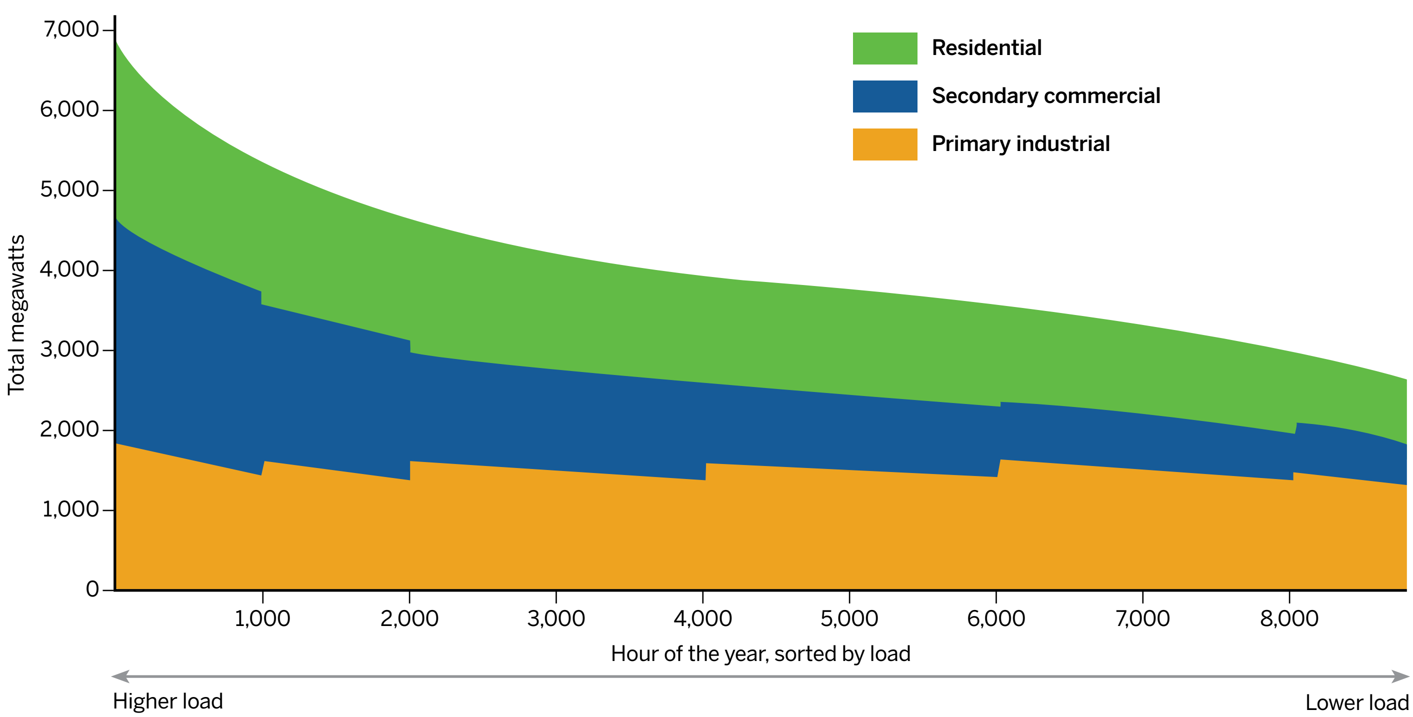


Table 17. Class share of each generation type under probability-of-dispatch allocation

Customer class	Generation source: Nuclear	Coal	Combined cycle	Peaking resources
Residential	34%	34%	32%	31%
Secondary commercial	28%	29%	39%	42%
Primary industrial	38%	37%	29%	27%

heating is electric, the residential class is likely to experience its highest load in the winter, even in places like Florida. The industrial class loads may peak in a variety of seasons, driven by vacation and maintenance schedules, variation in inputs (e.g., agricultural products) and demand, and other factors. The system peak may occur at a time different from all of the customer class NCP demands.

Table 17 shows how the costs of each generation resource would be allocated to the classes in the illustrative example in Figure 34. In the lowest-load hours, when nuclear is serving 80% of the energy load, the industrial class uses half the system energy and hence half the nuclear output; in the highest-load hours, when nuclear is serving about 29% of the load, the industrial class uses about 27% of the system energy. Averaged over the year, the industrial class uses 38% of the nuclear output. In the hours that the combustion turbines are running, the industrial class uses only 27% of the peaking resources' output, since the residential and commercial classes dominate loads in that period.

The commercial class is responsible for the largest share of the summer peak and hence of the combustion turbine costs but the smallest part of the low-load hours and hence the lowest share of the nuclear and coal costs. Every class pays for a share of each type of generation.[107]

The POD method has been applied with a wide range of detail. The generation "dispatch" over the year may represent historical or forecast operation, equivalent availability or capacity factor, seasonal variation (due to maintenance outages, hydro output, natural gas price, off-system purchases and sales), actual hourly output (reflecting planned and random outages and unit ramping constraints) and other variants. The POD method is thus one approach to hourly allocation. Ideally, dispatch and class loads should use the available data to match costs with usage as realistically as possible.

The POD approach has some limitations. Most importantly, it does not consider the reason that investments were incurred, only the way they are currently used. The costs of an expensive coal plant no longer needed for baseload service and converted to burn natural gas and operating at a 10% capacity factor to meet peak loads might be allocated in exactly the same way as the costs of a much less expensive combustion turbine operating at 10% capacity factor.[108] The excess costs of the converted coal plant are due to its historical role of providing large amounts of energy at then-attractive fuel costs; those costs were not incurred for the 10% of hours with highest demand. The same considerations arise for other steam plants that operate at much lower capacity factors than they were planned for and justified by. Some hydro plants have also changed operating patterns from their original use, either running for more hours to maintain downstream flow or for fewer hours due to reduced water supply. Peaking capacity is used to provide a range of ancillary services at many load levels, including upward ramping services (when load surges during the day or wind and solar output falls) and operating reserves (especially to back up large generation and transmission facilities). Reflecting these considerations may require modification of the inputs to the POD analysis, which considers only current use, not historical causation.

Second, the POD method spreads the cost of each resource equally to all hours or energy output, assigning the same cost of a totally baseload plant (with a 100% capacity factor) to the lowest-load off-peak hour as to the system peak hour. That approach comports with some concepts of equity and cost responsibility: The cost of each resource is allocated

107 If this example had included a street lighting class, that class might not have been allocated any combustion turbine costs if the lights would not be on in the summer peak hours. In a more realistic example, including outages of the baseload plants, the combustion turbines probably would operate in some hours with street lighting loads and the lighting class would be allocated some combustion turbine costs.

108 In the simpler forms of POD, the costs of both plants would be spread over the top 10% of hours. In more sophisticated approaches that map generation to actual operating hours, the steam plant would generate in many hours with load lower than the top 10%, while missing some of the top 10%, due to limits on load following.

proportionately to the classes that use it. On the other hand, it can be argued that the hours with higher marginal energy costs contribute more of the rationale for investing in that resource and that, in a sense, each kWh of usage at high-load times should bear more of the resource's investment-related costs than should each kWh in the off-peak hours. This concern can be addressed by weighting the energy over the hours, such as in proportion to some measure of hourly market price.

Third, it is important that the load and dispatch data be representative of the cost causation or resource usage in the years for which the cost allocation will be in place. For example, a baseload plant may have operated at only 40% capacity factor in the most recent year because of major maintenance or availability of economic energy imports. Or load and dispatch in the last 12 months of data may be atypical because of an extremely cold winter and mild summer. The POD allocation should be based on weather-normalized dispatch and load, just as the rate case costs allowed by the regulator and included in the cost of service study should reflect weather-normalized load.

Decomposition

Class obligations for generation costs have occasionally been addressed by dividing the generation resource into separate generation systems serving hypothetical loads for portions of the utility's customers, such as just the residential customers, just the commercial customers and just the industrial customers. For example, industrial customers in Nova Scotia have argued that their high-load-factor demands could be served by the capacity and energy of some set of baseload plants, where those costs are lower than the average generation cost per kWh (Drazen and Mikkelsen, 2013, pp. 11-16). The industrial advocates for this approach assume that the flat industrial load would be served exclusively by baseload plants and that all other costs should be allocated to other classes.[109] A similar approach might inappropriately be suggested to justify allocating the highest-cost resources to customers with behind-the-meter solar generation and lower-cost resources to nonsolar customers whose load does not dip in midday. The method might also be used to test whether classes are paying for enough capacity to cover their energy and reliability requirements.

In the context of resources stacked under a load duration curve, such as that shown in Figure 33 on Page 119, the decomposition approach allocates the resource mix horizontally, rather than the vertical allocation used in the POD method. Figure 35 on the next page illustrates the decomposition approach.

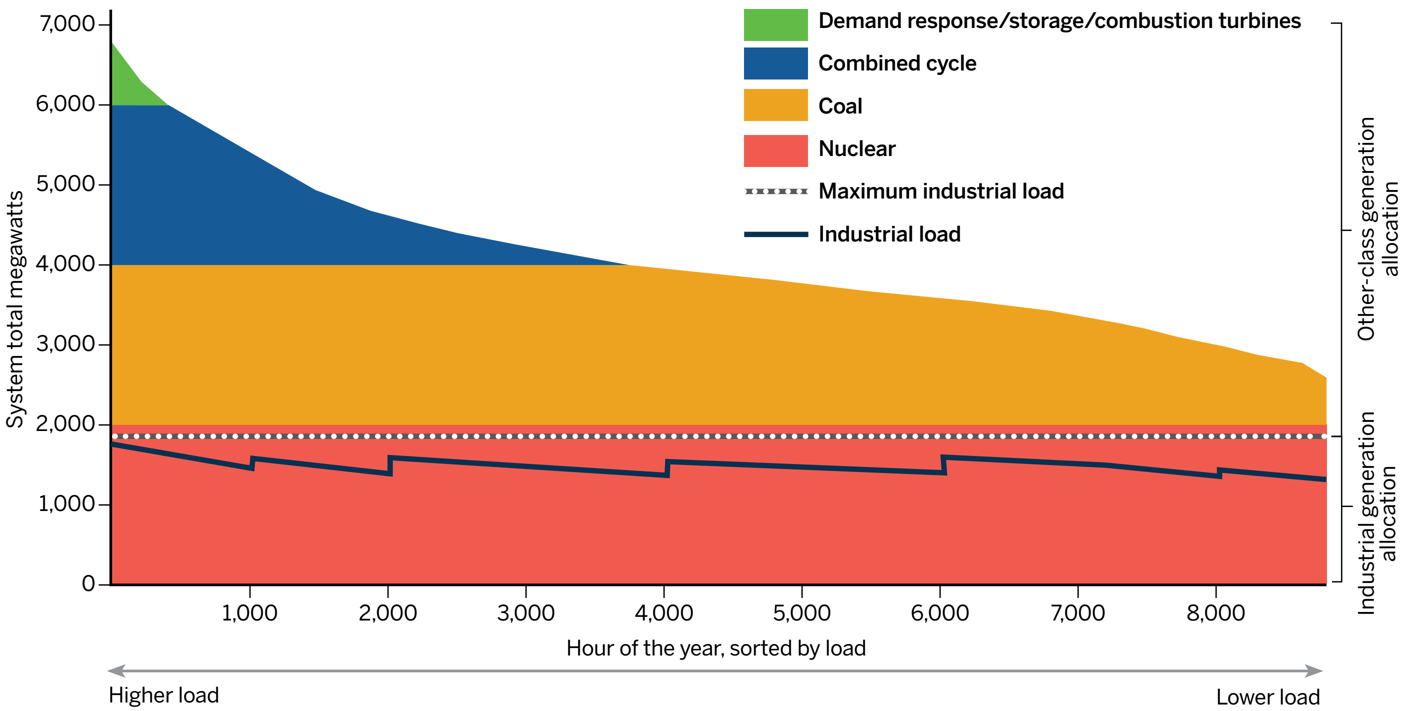
In essence, the decomposition method treats the utility as if it were multiple separate utilities. In the case of Figure 35, the utility system is decomposed into an all-nuclear system with enough capacity to meet the industrial peak load, and a utility with a little nuclear and all the other resources to serve all other load. Whether the industrial customers would support this allocation would usually depend on the cost of the nuclear resources compared with the system average.

The decomposition approach conflicts with reality in many ways, including:

1. The reserve requirements for the decomposed systems would be driven by their noncoincident class peaks or high loads (if they are assumed to be fully free-standing), requiring additional hypothetical capacity for utilities that are not already extensively overbuilt. If the decomposition assumes that the multiple class-specific systems would operate in a power pool, contribution to the system peaks would drive capacity requirements.
2. A system with a high load factor and relatively few large units would require a very high reserve margin (as discussed in Subsection 5.1.1) to cover fixed outages and even maintenance outages. The reserve units would operate in many hours (since the system load would always be near the allocated baseload capacity).
3. A baseload-only system would require a large amount of backup supply energy, either from hypothetical units or as purchases from the other classes.
4. The decomposition approach is usually designed to assign the lowest-cost resources to the industrial class,

109 A decomposition method that accounts for all relevant factors may not show an advantage for industrial customers. In Alberta, a related method to the decomposition method was presented to demonstrate that baseload power for industrial customers would be considerably more expensive than the demand-based cost allocation of the existing system for the industrial class (Marcus, 1987).

Figure 35. Illustration of decomposition approach to allocating resource mix



shifting all the costs of mistakes and market changes onto the other classes. That includes excess capacity (even excess baseload and capacity made excess by decline in industrial loads), the costs of fuel conversion and the high costs of plants built as baseload but currently operated as peakers.

5. It is not clear how variable renewables and other unconventional resources would be incorporated into the decomposed utility systems.

It is possible (if not certain) that the decomposition approach could be expanded and revised to create a viable classification and allocation method, but at this point no such model has been developed.

9.1.4 Other Technologies and Issues

Several types of generation costs do not fit neatly into the classification methods discussed in the previous sections. Some of those costs, such as hydro resources and purchased power, have been part of utility cost structures since before the development of formal cost of service studies. Others, such as excess capacity and uneconomic investments, became prominent in recent decades. More recently, utilities have needed to deal with allocating nonhydro renewable costs; a few utilities already have significant costs for nonhydro storage (mostly batteries) and most will need to deal with those costs in the future. As technologies change, new cost allocation challenges will arise — for new resources, repurposed existing assets and newly obsolete resources.

Fuel Switching and Pollution Control Costs

Many fuel conversion investments have been undertaken to reduce fuel costs or increase the reliability of fuel supply for high-capacity-factor power plants. This category includes:

- Conversion of oil-fired steam plants to burn coal in the 1970s and 1980s (most of which have since been retired).
- Conversion of gas-fired plants to burn oil in the 1970s, when the supply of gas was limited.
- Conversion of oil-fired plants to co-firing or dual firing with gas since the 1990s to achieve environmental compliance and reduce fuel costs.
- Conversion of coal-fired plants to partial or full operation on gas to achieve environmental compliance.
- Conversion of coal-fired plants to partial or full

Table 21. Illustrative example of time-of-use allocation of energy-classified costs

	Period (and annual hours)			
	Peak (50)	Midpeak (2,000)	Off-peak (6,710)	Total
Consumption (MWhs)	170,000	4,170,000	7,045,500	11,385,500
Cost per MWh	$48.53	$38.25	$35.71	$36.83
Class				
Residential				
Consumption (MWhs)	69,250	2,080,000	2,818,200	4,967,450
Allocated costs	$3,360,662	$79,558,753	$100,650,000	$183,569,415
Commercial				
Consumption (MWhs)	85,000	1,460,000	2,113,650	3,658,650
Allocated costs	$4,125,000	$55,844,125	$75,487,500	$135,456,625
Industrial				
Consumption (MWhs)	15,750	630,000	2,113,650	2,759,400
Allocated costs	$764,338	$24,097,122	$75,487,500	$100,348,961

Note: Numbers may not add up to total because of rounding.

transmission constraints preclude additional exports. That approach recognizes that using energy in some time periods is more expensive for Manitoba Hydro (in terms of lost export revenues) than consumption in other time periods.

9.3 Allocating Demand-Related Generation Costs

As discussed in Subsection 9.1.3, some classification methodologies, such as probability of dispatch and more granular hourly variants, simultaneously develop cost by period and the associated allocation factors driven by use by period. This section describes methods for developing allocation factors for demand-related costs developed by legacy demand/energy classification methods.

Typically, utilities allocate demand-related generation based on some form of class contribution to system peak loads, referred to as coincident peak. The loads that determine how much capacity a utility requires may be concentrated in a few hours a year, a few hours in each month, the highest 50 or 100 hours in the year, or some other measure of the loads stressing system reliability.

Frequently used demand allocators include:

- The class contributions to the annual system coincident peak (1 CP).
- The class contributions to three or four seasonal peaks (3 CP or 4 CP).
- The average of the class contributions to multiple high-load hours, such as:
  - The 12 monthly peaks (12 CP).
  - All hours with loads greater than a threshold, such as 80% to 95% of annual peak.
  - **Peak capacity allocation factor** (PCAF), a technique developed in California that weights high-usage hours based on how close each hour is to the peak hour.
  - Hours with some expectation for loss of energy.
  - Hours in which the system is stressed (e.g., operating reserves are below target levels).

As discussed in Chapter 5, generation capacity requirements have always been driven by more than a few hourly loads. Moreover, with peak loads being offset by solar generation and expanding demand response available to serve the highest-load or highest-cost hours, capacity requirements are driven by an even broader group of hours, which should be reflected in the development of the demand allocation factors. Broader allocation factors also have the virtue of limiting the instability resulting from the use of a limited number of peak hours. For example, ERCOT experienced an annual peak in 2017 at approximately

69,500 MWs on July 28 at 5 p.m. However, there were 13 other hours within 2% of that annual peak in 2017, in the hours ending at 3 p.m. to 7 p.m. (Electric Reliability Council of Texas, 2018, and calculations by the authors). Changes in temperature or cloud cover could shift the peak load to any of those hours. The peak timing in the load data can be very important in determining the allocators. The residential class typically will have a greater share of a peak load occurring at 7 p.m. than one occurring at 3 p.m. or 4 p.m.[126]

Utilities have sometimes allocated generation demand costs on the class NCP at the system level.[127] This approach may have been roughly appropriate for some utilities serving distinct classes with peak demands in different seasons, such as winter-peaking ski resorts and summer-peaking irrigation pumping, with both seasons contributing to the need for generation capacity. The class NCP would not recognize whatever load the ski resorts' summer operations contribute to the pumping-dominated peaks and would allocate demand costs to other classes based on their summer or winter peaks — but not their contributions to either of the seasons' high-load hours. Since reliability computations and the need for generation capacity are driven by combined system load, some measure of the combined loads on the system is relevant. With the hourly data collection technologies now available, this class NCP approximation is no longer necessary.

Traditionally, without access to the kind of sophisticated hourly data we can obtain today, utilities have tended to allocate demand costs on a single annual coincident peak, the average of the four monthly peaks in the high-load summer season, the average of some number of summer and winter monthly peaks, a defined number of peak hours when peaking resources are expected to operate, or the average of the 12 monthly peaks.[128] The number of months included in the computations of the demand allocator often reflects the following factors:

- The number of months in which the system may experience its annual peak load.
- Whether high loads occur in both summer and the winter.
- Whether requirements for maintenance outages reduce available capacity in off-peak months enough that available reserves in those months are comparable to the reserves in the peak months.

A more comprehensive approach to these factors would develop the demand allocator from all the hours identified in a loss-of-energy expectation study, after accounting for maintenance scheduling. Depending on the system, that may be several hours or several hundred hours. If data are not available for a comprehensive loss-of-energy expectation analysis, a demand allocator based on all hours within a specified percentage of the peak (e.g., 80% to 95%) or based on a significant number of the highest hours in the year (e.g., 100) is preferable to a coincident peak analysis. In sum, averaging or weighting a small number of coincident peaks incorrectly assumes that the need for capacity is a simple function of the amount of the system monthly peak, even though capacity requirements are driven by many hours,

126 The range of loads in these 14 hours was only about 1,400 MWs, roughly the size of one large nuclear unit or two large coal units. The differences in loads over those hours are of little significance in terms of reliability.

127 In some jurisdictions, the class NCP is referred to as the maximum class peak, maximum diversified demand or something similar, and "NCP" is used to designate the sum of the individual customer noncoincident peaks within each class. We refer to class NCP and customer NCP in this manual to distinguish between the two methods.

128 FERC has a set of guidelines for determining whether wholesale demand-classified costs should be allocated on 3 CPs or 12 CPs (for example, see Federal Energy Regulatory Commission, 2008, pp. 30-35). FERC's approach does not contemplate that any other number of months (such as four or eight) might be responsible for the need for capacity.

Table 22. Attributes of generation demand allocation options

Method	Data and computational intensity	Accuracy of cost causality	Allows joint classification/ allocation	Applicability
1 CP	Very low	Very low	No	Rare
3 CP; 4 CP	Low	Low	No	One-season peak; needle peaks
12 CP	Low	Low to medium	No	Multiple seasonal peaks; extensive maintenance requirements; class load shapes near peak similar
Multiple hours near peak (e.g., top 100 hours)	Low to medium	Medium	No	Broad, but loss-of-energy expectation gives more robust results if data exist to calculate them
Loss-of-energy expectation	High	High	No	Broad
Complex base-intermediate-peak	High	High	Yes	Broad
Probability of dispatch	Medium to high	High	Yes	Broad

depending on load; the amount of generation capacity that is available, not just installed; and the scheduling of maintenance outages.

Table 22 summarizes some characteristics of the allocation methods described in this section, along with the POD method described in Subsection 9.1.3 and the more complex variants of the BIP method from Subsection 9.1.2.

9.4 Summary of Generation Allocation Methods and Illustrative Examples

As demonstrated in many ways in the previous sections, it is appropriate to classify some of the long-term investment and O&M costs to energy usage rather than to demand. Table 23 presents a simplified view of appropriate classification results by plant type.

As variable renewable capacity (mostly wind and solar) on a system increases, the role for baseload capacity decreases. At some point, in hours with low load and high renewable output, traditional baseload resources will run only if they cannot shut down and restart on a timely basis.

Cost of service studies can also combine features of the various classification approaches, such as classifying peakers as 100% demand-related; classifying fuel conversion costs, environmental costs and generation without firm transmission as 100% energy-related; and applying the average-and-peak

Table 23. Summary of conceptual generation classification by technology

Resource type	Function	Classification
Nuclear, some hydro and best coal	Baseload	Primarily energy
Modern combined cycle, best gas-fired steam and mediocre coal	Intermediate	Energy and demand
Combustion turbines, mediocre fossil-fueled steam and combined cycle	Peaking and operating reserves	Primarily demand or on-peak energy
Storage and flexible hydro	Peaking and energy shifting	Demand or on-peak energy
Wind and solar	Energy and some capacity	Primarily energy

Note: "Best" refers to resources with the lowest variable costs, "mediocre" to those with higher variable costs. Resources that are worse than mediocre are likely candidates for retirement. "Intermediate" refers to generation that is neither baseload nor peaking.

Table 24. Summary of generation allocation approaches

Resource type	Classification and allocation methods: Legacy	Modern	Evolving
Nuclear	CLASSIFICATION: Average and peak ENERGY ALLOCATOR: All energy DEMAND ALLOCATOR: 12 CP	CLASSIFICATION: Equivalent peaker ENERGY ALLOCATOR: All energy DEMAND ALLOCATOR: Loss-of-energy expectation	All hours
Baseload coal	CLASSIFICATION: Average and peak ENERGY ALLOCATOR: All energy DEMAND ALLOCATOR: 12 CP	Probability of dispatch	Hours dispatched
Combined cycle	CLASSIFICATION: Average and peak ENERGY ALLOCATOR: All energy DEMAND ALLOCATOR: 12 CP	Probability of dispatch	Hours dispatched or used for reserve
Gas-fired steam	CLASSIFICATION: Average and peak ENERGY ALLOCATOR: On-peak energy DEMAND ALLOCATOR: 4 CP*	Probability of dispatch	Hours dispatched or used for reserve
Peaker	CLASSIFICATION: 100% demand DEMAND ALLOCATOR: 4 CP or 12 CP	Probability of dispatch	Hours dispatched or used for reserve
Hydro	CLASSIFICATION: Average and peak ENERGY ALLOCATOR: All energy DEMAND ALLOCATOR: 12 CP*	Probability of dispatch	Hours dispatched or used for reserve
Wind	CLASSIFICATION: 100% energy ENERGY ALLOCATOR: All energy	CLASSIFICATION: Equivalent peaker ENERGY ALLOCATOR: All energy DEMAND ALLOCATOR: Loss-of-energy expectation	Hours of output
Solar	CLASSIFICATION: Average and peak ENERGY ALLOCATOR: On-peak energy DEMAND ALLOCATOR: 4 CP	CLASSIFICATION: Equivalent peaker ENERGY ALLOCATOR: All energy DEMAND ALLOCATOR: Loss-of-energy expectation	Hours of output
Storage	CLASSIFICATION: Average and peak ENERGY ALLOCATOR: All energy DEMAND ALLOCATOR: 12 CP	Probability of dispatch	Hours dispatched, used for reserve or reducing ramp rate
Demand response	CLASSIFICATION: 100% demand DEMAND ALLOCATOR: 3 CP to 12 CP**	CLASSIFICATION: 100% demand DEMAND ALLOCATOR: 3 CP to 12 CP**	Hours dispatched or used for reserve

* Depends on use of resource
** Depends on program type and technology

approach to the remaining costs. A hybrid approach is only as equitable as the component techniques but may be useful where particular classification decisions can be made before the application of a generic approach to the residual costs.

Table 24 summarizes examples of allocation factors that might be applied to the capital and nondispatch O&M costs for various types of generation resources, whether utility-owned or purchased.[129] This summary is, by its very nature, highly simplified, ignoring many of the complexities discussed in sections 9.1, 9.2 and 9.3.

129 The probability-of- dispatch and hourly approaches can also be applied to the short-run variable costs of the resources.

For simplicity, we show an illustration only for generation investment-related costs. Table 25 shows the amount of investment in each category, which we will then divide using multiple allocation methods.

Table 26 shows two currently used methods: a legacy 1 CP system measure and a more modern method, equivalent peaker, where 80% of baseload costs are considered to be energy-related. The illustrative load data and allocation factors are from tables 5 through 7 in Chapter 5.

Table 27 shows the calculation of an hourly allocation model, where baseload costs are apportioned to all hours, peaking and intermediate costs to midpeak hours, and storage only to the 2% of usage at the most extreme hours.

Table 25. Illustrative annual generation data

	Net generation (MWhs)	Annual nonfuel revenue requirement	Annual nonfuel cost per MWh
Baseload	1,860,000	$74,400,000	$40
Peaker	534,000	$42,720,000	$80
Solar	1,056,000	$31,680,000	$30
Storage	62,000	$6,200,000	$100
Total	3,512,000	$155,000,000	$44

	Disposition of net generation
Storage input and delivery losses	412,000
Sales to customers	3,100,000

Note: Numbers may not add up to total because of rounding.

Table 26. Allocation of generation capacity costs by traditional methods

	Residential	Secondary commercial	Primary industrial	Street lighting	Total
1 CP (legacy)	$51,667,000	$62,000,000	$41,333,000	$0	$155,000,000
Equivalent peaker	$50,333,000	$52,400,000	$47,750,000	$4,517,000	$155,000,000

Note: Numbers may not add up to total because of rounding.

Table 27. Modern hourly allocation of generation capacity costs

	Residential	Secondary commercial	Primary industrial	Street lighting	Total
Baseload (all hours)	$24,000,000	$24,000,000	$24,000,000	$2,400,000	$74,400,000
Peaker (midpeak)	$14,424,000	$15,735,000	$12,326,000	$236,000	$42,720,000
Solar (daytime)	$10,560,000	$12,320,000	$8,800,000	$0	$31,680,000
Storage (critical peak)	$2,366,000	$2,366,000	$1,420,000	$47,000	$6,200,000
Total hourly allocation	$51,350,000	$54,421,000	$46,545,000	$2,683,000	$155,000,000
Composite hourly factor	33%	35%	30%	2%	100%

Note: Numbers may not add up to total because of rounding.

11.3.6 Direct Assignment of Distribution Plant

Direct cost assignment may be appropriate for equipment required for particular customers, not shared with other classes, and not double-counted in class allocation of common costs. Examples include distribution-style poles that support streetlights and are not used by any other class; the same may be true for spans of conductor to those poles. Short tap lines from a main primary voltage line to serve a single primary voltage customer's premises may be another example, as they are analogous to a secondary distribution service drop.

Beyond some limited situations, it is not practical or useful to determine which distribution equipment (such as lines and poles) was built for only one class or currently serves only one class and to ensure that the class is properly credited for not using the other distribution equipment jointly used by other classes in those locations.

11.4 Allocation Factors for Service Drops

The cost of a service drop clearly varies with a number of factors that vary by class: customer load (which affects the capacity of the service line), the distance from the distribution line to the customer, underground versus overhead service, the number of customers sharing a service (or the number of services required by a single customer) and whether customers require three-phase service.

Some utilities, including Baltimore Gas & Electric, attempt to track service line costs by class over time (Chernick, 2010, p. 7). This approach is ideal but complicated. Although assigning the costs of new and replacement service lines just requires careful cost accounting, determining the costs of services that are retired and tracking changes in the class or classes in a building (which may change over time from manufacturing to office space to mixed residential and retail) is much more complex. Other utilities allocate service lines on the sum of customer maximum demands in each class. This has the advantage of reflecting the fact that larger customers require larger (and often longer) service lines, without requiring a detailed analysis of the specific lines in use for each class.

Many utilities have performed bottom-up analyses, selecting a typical customer or an arguably representative sample of customers in each class, pricing out those customers' service lines and extrapolating to the class. Since the costs are estimated in today's dollars, the result of these studies is the ratio of each class's cost of services to the total cost, or a set of weights for service costs per customer. Either approach should reflect the sharing of services in multifamily buildings.

11.5 Classification and Allocation for Advanced Metering and Smart Grid Costs

Traditional meters are often discussed as part of the distribution system but are primarily used for billing purposes.[167] These meters typically record energy and, for some classes, customer NCP demand for periodic manual or remote reading and generally are classified as customer-related. Meter costs are then typically allocated on a basis that reflects the higher costs of meters for customers who take power at higher voltage or three phases, for demand-recording meters, for TOU meters and for hourly-recording energy meters. The weights may be developed from the current costs of installing the various types of meters, but as technology changes, those costs may not be representative of the costs of equipment in rates.

In many parts of the country, this traditional metering has been replaced with advanced metering infrastructure. AMI investments were funded in many cases by the American Recovery and Reinvestment Act of 2009, the economic stimulus passed during the Great Recession, but in other cases ratepayers are paying for them in full in the traditional method. In many jurisdictions, AMI has been accompanied by other complementary "smart grid"

167 Some customers who are small or have extremely consistent load patterns are not metered; instead, their bills are estimated based on known load parameters. The largest group of these customers is street lighting customers, but some utilities allow unmetered loads for various small loads that can be easily estimated or nearly flat loads with very high load factors (such as traffic signals). An example of an unmetered customer from the past was a phone booth. Unmetered customers should not be allocated costs of traditional metering and meter reading.