loads in areas such as water supply and delivery (see Marcus, 2010b, and Lazar, 2016), one of the options the California ISO identified was gas-fired generation. New storage options may be especially well suited for dealing with problems of ramping because of the timing of both charging and discharging batteries or taking other actions like storing hot or chilled water.

Equating a marginal capacity cost based on a peaker with very short-run energy costs creates a mismatch that is detrimental to customers with peakier load shapes. Several points must be considered here.

1. Costs of peakers vary. Smaller combustion turbines and aero-derivative turbines are more expensive than larger combustion turbines. Some of these smaller turbines have costs that approach or even exceed the cost of a larger combined cycle plant.[219] When conducting marginal cost studies, some utilities and industrial customers have requested approval for expensive peakers as marginal capacity costs.[220] However, that point ignores the key finding of the NERA method: that the marginal cost of capacity is the least costly source of capacity, so that by definition the more expensive peaker installed for other reasons is not the marginal cost of capacity under that framework.
2. Financing costs for peakers vary. In California, a number of parties (including E3) have used merchant plant financing, which is more expensive than utility financing, to develop the marginal cost of capacity. Again, the issue is that a merchant plant is not the least costly source of capacity because merchant plants have higher required returns. Furthermore, merchant plants often have off-take contracts that are shorter than the physical life of the plant. Using the shorter contract life for capital recovery also inappropriately increases the marginal cost of generating capacity.
3. Even a peaking power plant would make money in the market (or save fuel and purchased power costs in a vertically integrated utility that is not closely affiliated with a market). Combustion turbines installed in the 1970s, when the NERA method was developed, had heat rates in the range of 15,000 Btu per kWh and burned expensive diesel oil. They were machines that provided essentially pure capacity — reserves that were turned on to keep the lights from going out. Much of the gas-fired load at that time came from less flexible steam plants with heat rates from 9,000 to 12,000 Btu per kWh. Modern peakers have a heat rate in the range of 10,000 Btu per kWh (or lower) and burn gas. They actually have better heat rates than many of the older intermediate steam plants, as well as greater flexibility. As a result, when modern peakers are used, they generally earn at least some money in the market or save fuel and purchased power costs.[221] They also can earn revenue from selling dispatch rights in the 10-minute (nonspinning) reserve ancillary service market. This revenue should be netted against the cost of the combustion turbine, because it pays a portion of the cost of capacity.
4. Peaking generation may not be the least-cost capacity resource. It is possible for an intermediate resource such as a combined cycle generator to have a lower net cost than a combustion turbine. In particular, the capital and long-term O&M cost of the combined cycle generator minus the revenue that it would earn in the market or the fuel it would save can be less than the cost of a combustion turbine. Even with excess capacity, this outcome can sometimes occur, particularly if a relatively expensive turbine is erroneously considered as the peaking unit (as discussed earlier in this list).
5. Storage costs may be cheaper than combustion turbines. Under current conditions, it is possible that storage costs net of energy savings relative to market prices can be cheaper than conventional peaking generation. In particular, PG&E is installing and contracting for about 550 MWs of batteries with four-hour storage to meet system needs and replace 570 MWs of RMR peaking and

219 A utility might have installed some of these smaller turbines for reasons such as alleviating transmission constraints, meeting time constraints (if the smaller turbines had less stringent siting requirements) or responding to specialized system needs such as black start capability.

220 See, for example, Phillips (2018, pp. 5-11), where the testimony argues for the usage of a 50-MW turbine costing $1,600 per kW instead of a cheaper 100-MW turbine.

221 See Section 1.1 for more discussion and quantitative examples of this phenomenon.

combined cycle generation (Maloney, 2018; California Public Utilities Commission, 2018). RMR generation receives payments on a cost of service basis including capital and operating costs, although the specific plants being replaced are partly depreciated.

6. Additionally, pure capacity can be available at considerably lower costs than a combustion turbine. Systemwide actual and projected prices in the California resource adequacy markets are $30 to $40 per kW-year over the period of 2017-2021 (Chow and Brant, 2018, p. 21) with even the peak monthly prices from July to September rising no higher than $4.50 per kW-month (Chow and Brant, p. 32). Capacity market prices are generally similar in the PJM region, with higher prices in transmission-constrained pockets of New Jersey and occasionally other areas; new demand resources, renewables and gas-fired combined cycle generation have been added at those low prices (PJM, n.d.).[222] Resource adequacy capacity does not come with the physical hedge against high market prices provided by the combustion turbine's known heat rate, but it is much less costly. It is arguably the newest version of "pure capacity" as NERA originally defined it. PG&E estimates the capacity cost during a period of surplus as the long-term O&M cost of a combined cycle generating plant, because a combined cycle plant that could not earn its long-term O&M would go out of service, reducing any available surplus (Pacific Gas & Electric, 2016, Chapter 2).

In sum, the combustion turbine peaker that is the typical choice for marginal capacity costs under the NERA method, as well as under long-run incremental costs, is likely to significantly overstate capacity costs given the economics of new large-scale storage facilities and significant capacity surpluses.

To the extent there is a marginal capacity cost for ramping capability, it can best be understood as an hourly capacity cost that is negative in the hour or two before the ramp begins, a positive hourly cost in the steepest several hours of the ramp and lower but still positive hourly cost as the ramp becomes flatter, continuing through and just beyond the evening peak.

But, for allocation purposes, the cost needs to be first divided between ramp caused by customer loads and ramp caused by generation characteristics, which should be feasible. This is another example of how the emerging wind- and solar-dominated grid challenges traditional methods of cost allocation. To the extent that the need for capacity for ramping, and hence part of its cost, is caused by generation characteristics, it should not be a load-related marginal cost for allocation to the classes that contribute to the ramp.[223] The generation-related ramp effectively becomes part of the cost of the generation resources causing the ramp under a short-run marginal cost theory, such as the one NERA defined. To the extent that generation-related ramping costs are recovered as incurred periodically in energy costs or ancillary service or other charges from the RTO, they should be part of marginal energy costs. Although these concepts are relatively clear, their implementation is not clear at all, with disagreements among parties on both the generation-related portion of ramp costs, the definition of ramp hours (for example, whether more than one large ramp should be counted on a single day) and the method of allocating costs to both hours and classes. Storage units are more effective for ramping than thermal peakers because they can both charge in the preramp hours and discharge to clip the peak, reducing the total amount of ramp more than a thermal plant, whether the storage is installed as a bulk power resource or for other purposes.

222 Similar capacity prices have prevailed in New York, outside the New York City load pocket (New York Independent System Operator, n.d.). Capacity prices in MISO are even lower due to a continuing surplus and renewable additions, while prices in New England were higher for a few years after 2016 and have recently fallen to the California range.

223 Although the generation-related cost should not be part of the class allocation, it may be appropriate to include some of that cost in rate design to provide a greater discouragement to ramping loads.

20. Transmission and Shared Distribution in Marginal Cost of Service Studies

20.1 Marginal Transmission Costs

Marginal transmission costs have not received the attention that marginal generation and distribution costs have received, because in large parts of the country transmission is partly if not wholly under FERC jurisdiction. Thus, California utilities only calculate marginal transmission costs as an input to the process of calculating the contribution to margin of economic development rates, rather than for cost allocation and rate design. Nevada calculates marginal transmission costs using the NERA method. But since there is no joint product (such as generation energy and capacity, or distribution lines and customer connections) and Nevada allocates costs by functions (see Chapter 24), there is little controversy. Southern California Edison breaks its transmission costs into transmission (115 kV and above) and subtransmission (69 kV and below) because specific factors relating to the physical layout of its system left its subtransmission system under Public Utilities Commission regulation, where it is treated as part of the company's distribution marginal costs.[224]

The NERA method for marginal transmission costs involves some analysis of the relationship between transmission system design and peak loads. Although the original method involves regression analysis between cumulative investment in load-related transmission (calculated in real, inflation-adjusted dollars) and cumulative increases to peak load, two other methods have been developed. The first, the total investment method, examines total investment divided by the change in peak load. The second, the discounted total investment method, uses discounted total investment divided by the discounted change in peak load. This assigns lower weights to investments occurring later in a projected analysis period relative to investments occurring earlier. The specific choice among these three methods can create relatively small differences (unless miscalculated). The investment cost is annualized by multiplying by the RECC. Investment costs are defined narrowly. As an example typical of most utilities, Southern California Edison stated in its most recent rate design case:

> Projects discretely identified as load growth are only considered in the analysis. All projects not related to load growth (i.e., grid reliability, infrastructure replacement projects, grid modernization, automation, etc.) are excluded from this analysis (2017b, p. 37).

The NERA method can be applied to the transmission system as a whole or to transmission and subtransmission voltage levels and to lines and substations separately.

O&M costs are added to the annualized capital costs. There are two conceptual methods for doing this. The original NERA method averages O&M costs (in real terms) divided by kWs of load (i.e., calculated in dollars per kW) over a period containing both historical and forecast years. An alternative method used by PG&E calculates O&M costs as a percentage of plant and adds it only to the new plant. Using this method, O&M costs are lower because the assumption is made that O&M is tied to new plant rather than maintaining the system in order to retain all loads.

The NERA method essentially ignores large parts of the transmission system and therefore generally ends up with marginal transmission costs well below embedded costs. It also fails to recognize that peaking resources and storage are

224 California utilities calculate a marginal cost of transmission as an element of cost when determining how much contribution to margin is provided by loads such as economic development rates, but it is not used for allocation of costs to customer classes (which is done by FERC) and is therefore not reviewed carefully in rate cases.

often strategically located near loads where transmission is constrained to reduce the need for transmission. For example, the city of Burbank, California, incurred additional costs to locate the Lake generating unit in the heart of the urban area; an offsetting benefit was avoidance of transmission costs.

First, interties to connect utilities, or to connect remote generation plants for purposes of obtaining cheaper sources of generation and increasing imports of generation capacity, are often simply ignored. They are treated as "inframarginal" sources of generation (built because they were theoretically cost-effective relative to the existing system without those lines). As a result, the cost of interties ends up neither in the marginal generation costs (where the only effect is to depress short-run marginal energy costs) nor in the marginal transmission costs (because the NERA method assumes them to be a source of cheap generation). Nor do the net revenues the utility receives for off-system energy sales (to the extent that the concept still exists in competitive wholesale markets) end up as an offset to transmission costs, even though such sales could be one reason for constructing intertie capacity.

The second set of costs that methods like the NERA method ignore is the cost of system replacement. The argument is that once the utility commits to build one system of transmission, the RECC method has the effect of deferring all replacements. The end result is that, as pieces of the system that were built 30 to 60 years ago are replaced, they are part of the embedded costs but not part of the marginal costs. System replacements can be a significant portion of the cost of new rate base. This issue is discussed further in the next section.

Third, any transmission and distribution costs related to improving reliability on the existing system (instead of specifically adding new capacity) or automating the system (to improve reliability or reduce capacity needs) are excluded under the pure version of this method. This exclusion is at variance to the theory of marginal generation costs, where in equilibrium the value of avoided shortages equals the value of the least-cost resource able to meet the need. Here, avoided shortages are assigned no value.

Fourth, the transmission and subtransmission systems are heavily networked and are built to avoid outages under various load conditions throughout the year with one or two elements of the system out of service. This networking essentially means that even though the NERA method relates investment to peak, the cost causation of that relationship is unclear, and a significant portion of costs may be related to lower-load hours than the peak. The hourly allocation methods discussed in Section 25.2 may provide guidance in treating some transmission costs in marginal cost studies, by assigning these costs to all hours in which the assets are deployed.

20.2 Marginal Shared Distribution Costs

The most controversial issue for the calculation of marginal distribution costs is the same issue raised in the embedded cost section. Is a portion of the shared distribution system, particularly the poles, conductors and transformers in FERC accounts 364 through 368, customer-related? The authors of this manual believe strongly that these costs are not customer-related; Section 11.2 on embedded costs addresses this question in detail. This section will comment only on some specific issues of the customer/demand classification as they apply specifically to marginal costs for the shared elements of the distribution system.

The NERA method for marginal distribution capacity costs unrelated to customer connections is similar to that for marginal transmission costs, involving an analysis of the relationship between distribution system design and peak loads. Again, the three methods used are regression analysis, the total investment method and discounted total investment method, all discussed in Section 20.1. The investment cost is annualized by multiplying by the RECC.

The marginal cost of distribution capacity can be developed for the distribution system as a whole, as well as separately for lines and substations. A number of utilities (including Southern California Edison, San Diego Gas & Electric and the Nevada utilities) have separate calculations for distribution substations and lines. PG&E uses regional costs. It calculates costs individually for more than 200 distribution planning areas for purposes of economic development rates and aggregates them up to 17 utility divisions for purposes of marginal cost calculation for cost allocation and rate design (Pacific Gas & Electric, 2016, chapters 5 and 6). Using all of the distribution planning areas (as was proposed in the 1990s) is so granular that it would be difficult to examine and audit the relationship of costs to cost drivers. This is true in part because costs are dependent on the amount of excess capacity in local areas. In addition, customers who are large relative to the distribution system may never pay for capacity needed to serve them in some cases. And customers in slow-growing areas are charged less than those where load is growing faster, even if those customers are using a significant portion of the distribution system.

O&M costs are added to the annualized capital costs. As with transmission, there are two conceptual methods for doing this. The original NERA method averages O&M costs (in real terms) divided by kWs of load over a period containing both historical and forecast years. The alternative would calculate O&M costs as a percentage of plant and include it as an adder only to new plant.[225]

Southern California Edison and San Diego Gas & Electric aggregate all primary distribution circuit costs, including those that are part of line extensions, and treat them as demand costs. PG&E treats all primary distribution costs associated with line extensions as demand costs, again calculated regionally, but uses a different, less diverse measure of demand — demand at the final line transformer, rather than demand at the substation, to allocate these costs (Pacific Gas & Electric, 2016, Chapter 6).

The Nevada utilities make a distinction between costs covered by the line extension allowance (which they call facilities costs) and other distribution substation and circuit costs. Facilities costs are allocated to customer classes based on the cost of facilities built for each class that are recovered from customers because they are less than the line extension allowance. Costs are higher in dollars per customer in nonresidential classes than in the residential class. These costs are annualized by the RECC and have O&M added to them (Walsh, 2013, p. 9). This treatment is identical to the **rental method** for customer connection costs discussed in Section 21.1. Thus, as the line extension allowance is increased, more costs are allocated to residential customers because land developers pay fewer of them. Unlike most utilities, the Nevada utilities have separate rates for single-family and multifamily customers. The result of this split of the residential class is that multifamily customers, with less expensive hookups on a dollars-per-customer basis, do not subsidize single-family customers, in contrast to the case across most of North America when distribution circuit costs are partly assigned on a per-customer basis. We discuss the class definition issue in Section 5.2.

Central Maine Power, which uses marginal costs to allocate distribution costs, also divides the distribution system between line extension and other distribution facilities and uses a different allocation among classes for line extension costs that allocates the costs more heavily to residential customers (Strunk, 2018, pp. 14-18).

Pacific Power's Oregon rate cases have a "commitment-related" component to primary distribution costs that is similar to the minimum system methods used by utilities conducting embedded cost studies and has similar issues (Paice, 2013, pp. 6, 9-11). Although the Oregon utility commission has accepted this for interclass cost allocation purposes, it does not include these as customer-related in the rate design phase of rate-making (B. Jenks, Oregon Citizens' Utility Board, personal communication, June 4, 2019).

The NERA method again ignores replacement costs, which constitute the majority of new distribution plant for many utilities' systems, in addition to ignoring costs of improving reliability. A good argument can be made that replacement costs are truly marginal costs and that the utility needs to make replacements to serve its existing load safely and reliably. First, regardless of the workings of the RECC method, assuming that replacement costs are automatically committed when a new piece of distribution equipment is built is a monopoly-based argument and does not work in a truly competitive market. The marginal cost relates to both incremental and decremental demand. A replacement is needed to assure that demand does not decline but is instead

225 This is PG&E's method because the company claims that O&M costs are not marginal once the plant is installed (Pacific Gas & Electric, 2016, Chapter 5, p. 11).

served reliably. The fact that replacements are a marginal cost can be analogized to other industries, such as trucking. A more detailed theoretical exposition is given in Appendix D.

Adding in replacement costs (calculated in dollars per kW like O&M costs, but with an adder for the present value of revenue requirements) has been estimated in the past to increase marginal costs for Southern California Edison by 40% for distribution and 31% for subtransmission (Jones and Marcus, 2015, p. 30) and for PG&E by 46% for primary distribution and 27% for new business (Marcus, 2010b, pp. 36-37). Replacement costs were included as marginal costs in the 1996 PG&E gas cost adjustment proceeding (California Public Utilities Commission, 1995) but have not been included in any electric marginal costs because all California cases have been settled for almost 25 years.

Some distribution costs that are similar to replacement costs are actually policy-related and may not be marginal costs as a result (e.g., urban undergrounding of overhead lines; other changes related to safety and environmental protection). As with embedded costs and for the same reasons, costs in FERC accounts 364 through 367 should be considered as common system costs rather than as costs assigned to individual customers. Even though they are included in Account 368, as with embedded costs, capacitors and regulators need to at least be functionalized as primary distribution costs when calculating marginal costs, unless the dual function of the capacitor as a generation resource is recognized,[226] just as with embedded costs. They reduce losses and increase distribution capacity by supporting voltage and reducing amounts of reactive power.

Many smart grid investments such as automated switching and integrated volt/VAR controls (as well as potential investments in storage and targeted demand response programs) increase overcapacity and reduce distribution marginal costs calculated using the NERA method by reducing the need to build new lines. Under this method, this overcapacity will cause customer costs to be emphasized relative to other distribution costs.

Distribution marginal costs end up with tricky calculation issues because of differences in the determinants on which marginal cost calculations are made and the costing determinants on which revenue allocation is conducted. Not all kWs are equal. This issue is referenced here as a concern regarding marginal distribution costs but is addressed in more detail in Chapter 24 on reconciling marginal costs to embedded costs.

The transformer is an intermediate piece of equipment. In the larger C&I classes, a transformer will often serve a single secondary voltage customer, while for residential customers it may serve a single rural customer, a group of six to 10 suburban customers or 50 apartments or more. In the small and medium commercial classes, several customers are served by a single transformer in some cases, while some customers (particularly larger or three-phase customers) are served with single transformers. There are also differences in cost between single-phase and three-phase transformers. Single-phase equipment is adequate for serving nearly all residential customers and many small commercial customers.

Some utilities have allocated these costs to classes as marginal costs based on the average cost of a transformer serving the class. If this treatment is used for class allocation, transformer costs should not be fixed customer costs for purposes of rate design because of the wide variety of customer sizes and transformer configurations. In older urban areas, secondary line is often networked across several transformers, with some service drops connected directly to the transformer and some connected to the networked secondary line. In these cases, the use of secondary lines to connect the transformer to the customer is more of a common cost than a connection cost, unlike in more modern design configurations, where secondary distribution might be an economic alternative for customer connection.

If a transformer cost is considered part of the customer connection function, a portion of transformer costs is likely not marginal costs, and only the cost of the smallest transformer should be included. Transformers typically are purchased using an algorithm to minimize the present value of capital costs and load-related and nonload-related (core) losses. The extra costs of the transformers above the

226 If a capacitor is deemed to have a generation function, it is not a marginal cost at all under the NERA method.

minimum costs would be inframarginal costs of providing energy and capacity rather than customer connection costs. However, these extra costs have been difficult to measure in past cases. Also, many utilities claim that the new energy standards for line transformers mean they no longer need to optimize transformer costs against losses and they only need to meet but not exceed the federal standard. Capacitors and voltage regulators are also not part of transformer costs for either customer connection or secondary distribution demand but instead should be quantified together with other primary distribution costs.

21. Customer Connection and Service in Marginal Cost of Service Studies

The customer connection costs, also known as point of delivery costs, include the service drop and meter and may include the final line transformer and any secondary distribution lines that are not networked with other transformers.[227] Primary lines are typically not point of delivery costs, although several utilities include either line extension costs or some type of minimum system as customer costs. The basic customer method primarily includes the service and meter, although some states include a transformer. As a matter of calculation, it is necessary to determine a meter cost for each customer class. Additionally, customers cause the utility to incur costs of billing, collections and similar items.

21.1 Traditional Computation Methods

There are two longstanding methods for computing marginal customer connection costs. The first is the rental method, where the cost of new customer connection equipment is multiplied by the RECC to obtain a value at which a customer could be presumed to rent the equipment from the utility. O&M costs are added to these annualized capital costs. This method is a direct continuation of the NERA method.

The second method is the new-customer-only (NCO) method. It calculates a marginal cost based on the number of new hookups (and possibly replacements) of customer connection equipment in the same time frame as used to measure other marginal costs for generation and transmission. This cost is adjusted by a present value of revenue requirements multiplier to reflect the costs of income taxes and property taxes under utility ownership. Elements of the method were introduced by consumer advocates who recognized that the incremental and decremental costs of hooking up new customers were different (unlike most marginal cost elements) in the mid- to late 1980s. The specific NCO method was first presented by PG&E (in 1993; it has since disavowed the NCO method) and was adopted by consumer advocates with modifications after that time. Again, O&M costs are added.

The rental method has the longest time horizon of all the marginal cost methods in the entire panoply of marginal costs developed by NERA and used by regulators. All customers are assumed to rent equipment based on today's costs and configurations of customer connection equipment, which is largely underground in most newly constructed urban and suburban distribution systems. The method as utilities now implement it generally does not consider the standing stock of equipment. As a result, the rental method assumes that customers with overhead service in urban areas are charged in marginal costs as if they had underground service. So these customers not only have to look at wires and poles, but they face a revenue allocation that assumes they have the amenities of modern suburbs. By failing to use the standing stock, the rental method also assumes that the percentage of new housing stock built as apartments is the same as the percentage of existing housing units that are apartments.[228]

Besides these computational issues, there are significant theoretical issues that caused the development of the NCO

227 A secondary distribution line that is not networked is installed to reduce costs (including line losses) relative to running all services directly off a single transformer. It is thus an economic substitute for longer service lines.

228 The exception to this concern is Nevada, where separate marginal customer costs are calculated for single-family and multifamily homes based on new costs but are applied to the existing stock of each type of housing. This practice has been in place since at least 1999 when the utilities presented the division of the residential class in Public Utilities Commission of Nevada dockets 99-04001 and 99-04005. San Diego Gas & Electric calculates customer connection costs based on the noncoincident demand of the customers and uses demand estimates of existing customers, which also ameliorates this problem to some degree (Saxe, 2016, pp. 6-10).

method. Aside from computational inaccuracies from not using the standing stock, the rental method is not the outcome of a true competitive market. The NCO method reflects as marginal only those costs that are avoidable — incurred at the time when the choice to spend or not spend money on new hookups is made — when the customer chooses to connect to the utility system or when a hookup is replaced. It is thus a shorter-run marginal cost method than the rental method, making the NCO method more consistent with the other short- and intermediate-term means of calculating costs included in the rest of the NERA method. The cost analyst must carefully examine the consistency between the NCO method, which considers the full costs of system replacement, and the methods used for G&T. If replacement costs are used for one category, they should be used for all categories, moving the study toward a total service long-run incremental cost study (see Section 25.1).

The NCO method also comports better with competitive markets and consumer behavior. Consumers typically have the choice to either own or rent any equipment affixed to their homes that costs several hundred to a few thousand dollars. In many cases, consumers nearly always own the equipment, as in the case of curtains or chandeliers. In other cases, there is consumer choice as to ownership or rental, as with propane tanks, solar energy systems,[229] internet routers and (in some parts of North America) water heaters. Even where the rental option is present, the consumer can choose to purchase the equipment. In contrast, the rental method does not simulate the outcome of a competitive market. It is equivalent to assuming there are enough landlords that there is a competitive rental market, who own all the property in a given community. Anyone who wants to live in that community has to rent from one of these owners; no one is allowed to buy property. Rather, this is a market with barriers to entry that prevent true competition. Thus, the analogy of the current rental method to the housing market places an anti-competitive constraint on consumers that would limit their economic choices while protecting the profits of the landlord — or the utility, in this case — from the vagaries of competition.

There is one additional computational issue in the NCO method, where the replacement rate may or may not be considered. In California, the utility commission advocacy office has omitted replacements from the NCO method as well as from calculations of marginal distribution costs. The Utility Reform Network tends to include them for both, yielding higher costs for both demand distribution and customer-related costs. If a replacement cost is needed for the NCO method, utilities often use the highest possible number — the inverse of the depreciable life of the equipment. Although data for service drops may be limited, utilities often have actual rates of replacement of meters and transformers, as well as information that could allow the replacement rates for service drops to be inferred from capital budgeting documents.[230]

21.2 Smart Meter Issues

For utilities installing smart meters, a joint product issue arises. A smart meter with the associated data collection network hardware and software serves multiple functions. It provides customer connection and billing while reducing the labor costs of meter reading and other functions. It can also provide a number of other peak load, energy and reliability functions, including enabling TOU pricing and measuring demand response; load research; distribution smart grid functions such as outage detection and (if tied to utility GPS and mapping functions) identification of potential transformer overloads; and even, in some cases, internet access for utility customers.

The NERA method provides a theoretical underpinning that customer connections (analogous to generation capacity) should be provided by the least-cost method. In evaluating past smart meter cases, about 70% of the cost of the AMI system was covered by meter reading benefits; the remainder of the cost was justified by other benefits. Therefore, California

229 Solar systems may be a special case. Renting the equipment generates some tax benefits that can be passed to the consumer in lower rent, while ownership would not have the same tax advantages. This will change if the solar investment tax credit is allowed to expire after 2020 as would occur under current law.

230 There is an accounting issue for meter replacement, because the cost of the meter is capitalized but the cost of meter replacement O&M is often expensed (see Section 21.3). It is important not to count the same cost twice.

ratepayer advocates typically have argued that only 70% of the cost was a customer connection and billing cost and the remainder was not a marginal customer cost. Alternatively, in other studies, more than 100% of the smart meter and data collection installation cost is justified by other savings in power supply and line losses, rendering the metering and meter reading function as a cost-free byproduct.

The division of the smart meter into connection and billing and other benefits can be analyzed in a different way — by netting out all benefits from the smart meter aside from those associated with meter reading and customer accounts, leaving the remainder as connection-related. This is analogous to calculating a marginal capacity cost based on a combined cycle power plant net of savings of fuel and purchased power if it is cheaper than a combustion turbine.

21.3 Operations and Maintenance Expenses for Customer Connection

Most utilities that use marginal costs assign the costs of FERC accounts 586 and 597 (meter operations and maintenance) and possibly portions of accounts 583, 584, 593 and 594 (operations and maintenance of underground and overhead lines) related to services and transformers as customer-related. If a transformer is customer connection equipment, Account 595 (transformer maintenance) is also customer-related. Utilities also assign portions of overhead accounts 580 (supervision and engineering), 588 (miscellaneous operating expenses), 590 (maintenance supervision) and 598 (miscellaneous maintenance expenses) to the customer costs. The treatment of these expenses is often an issue, as the specific costs in many of these areas may be more related to shared distribution system costs than to customer connections. These costs typically are developed using an average of several years of historical data and several years of future data.

There are several computational issues.

First, at least some utilities include the labor cost of replacing a meter in Account 586 (Jones and Marcus, 2016, citing San Diego Gas & Electric testimony). Effectively, the cost of replacing meters for customers needing replacement is included in both the O&M costs and the capital costs (because the lessor has the responsibility of replacement in the rental method and the replacement is included in the NCO method). Therefore, replacement meter costs should be removed from Account 586 in the rental method because they would otherwise be double-counted as part of the rental cost. In the NCO method with replacement, the costs of meter installation should be removed from the capital costs for replaced units and left in Account 586 to reflect recurring replacements.

Second, there are issues relating to the real costs of operating and maintaining service drops, some of which also must be dealt with in embedded cost analysis. Utilities may assign costs to service drops based on investment or line miles. But as a practical matter, utilities spend very little on service drops as compared with primary distribution lines. In particular, many utilities have vegetation management standards almost entirely tied to primary lines. They rarely trim trees around secondary wires, except incidentally when primary line trimming is needed, and even more rarely trim trees around service drops, except under emergency conditions. Aside from tree trimming, patrols and inspections are driven by primary lines, not service drops. Therefore, it is necessary to conduct utility-specific analysis on service drop maintenance.

A third issue is that some of the costs in Account 588 are not marginal costs at all. For example, PG&E in a previous case included costs of obtaining additional revenue from nontraditional sources and costs of performing work reimbursed by others. Other costs do not apply to customer connection equipment (environmental costs and mapping expenses that generally do not apply to services and meters).

In addition, if smart metering is in the process of being installed or has just been installed, O&M costs of smart meter installation may be part of accounts 586 and 587 in some historical years. In that case, it will be necessary to identify and remove those costs or use a historical period of time entirely after smart meter installation.

21.4 Billing and Customer Service Expenses

A marginal cost analysis of billing and customer service expenses is usually done in one of two ways. The most common way, following the NERA method, is to average costs over a number of historical and projected years. These costs are calculated per weighted customer, recognizing that certain activities are more heavily related to some customers than others. The second method is to use the costs of revenue cycle services, which are **short-run incremental** costs used to pay competitive service providers, plus similar short-run calculations for call centers and other activities. These costs are less than embedded costs of the same functions used in the NERA method. PG&E chose this method in Phase 2 of its 1999 general rate case to be consistent with the lower marginal costs it calculated for paying competitors; it has kept this design ever since. A method based on revenue cycle services is more consistent with a short-run marginal cost theory, but many utilities may not have the ability to implement it.

Many of the issues related to the appropriate calculation of marginal costs of billing and customer service are similar to the embedded cost issues raised in this manual. As with the discussion of this issue in Section 12.1, the frequency of billing and collection is driven by usage; if customers used minuscule amounts of power, it would not be cost-effective to read meters (without smart meters) or even bill on a monthly basis. For utilities without AMI, costs in excess of bimonthly meter reading and billing could be considered revenue-related rather than related to customer accounting. Relatedly, if smart meters are being implemented or have recently been implemented, meter reading costs from periods before smart meter implementation (as well as other costs such as call center costs associated with the implementation process) must be removed to prevent double counting of the capital cost of the smart meter and the operating cost of the mechanical meter that the smart meter replaces. As with embedded costs (see Section 12.3), the costs associated with major account representatives assigned to serve large customers (regardless of the FERC accounts in which they are found) should be considered part of the marginal costs of serving those customers and should be assigned to them.

As with customer-related distribution costs, in jurisdictions using long averages with both present and future costs, the future cost forecast must be reasonable. In the specific case of customer accounting costs, a trend toward declining costs and increasing productivity has persisted for almost a decade. More customers are receiving and paying bills online or through automatic bank transactions, both of which are less expensive to the utility than mailing bills and payment envelopes to the customer and then opening and processing return envelopes with payments from customers. Phone calls to the utility are being replaced with internet transactions (even for items such as changing service or making payment arrangements) and the use of interactive voice response units. Even though utilities may claim that the remaining calls may be more complex, customer service representatives are logging fewer total hours. As a result, it is important to examine any set of averaged costs carefully. If costs are declining, as they should be, then an average would include costs from a period of worse productivity than the present and should not be used. Similarly, if the future is projected to be more expensive than recent history, that assumption should be probed for reasonableness.

Some customer accounting and customer-related metering and distribution O&M expenses are paid by fees, not rates (see Chapter 15). As a result, they are not marginal costs associated with the general body of ratepayers. Costs of activities such as establishing service; disconnection and reconnection after customer nonpayment; field collections; meter testing; and returned checks are offset by fees received from individual customers (largely residential customers). If the costs paid by the fees are allocated heavily to residential customers, but the fees are not included in the revenue to be allocated, this would effectively cause residential customers to pay twice: once in the rate and a second time when assessed the fee. This problem can be dealt with in either of two ways. Nevada includes the fees in the revenue to be allocated and directly assigns the fees as revenues received from the classes that pay them. California generally removes an amount equal to the fees from the marginal customer accounting cost. The methods are not identical, but both will address the double counting. Costs (and uncollectible accounts if necessary) related to billing and collecting money from non-energy activities such as line extension advances and other products and services besides the utility's energy bills may be in accounts 901 through 905, but they are not marginal costs of serving electric customers and should be excluded from marginal customer costs. This is similar to the approach in Section 15.2 for embedded costs.

In some cases, the difference between marginal and embedded cost analysis is that costs are excluded from marginal costs while being allocated differently from other costs as embedded costs. Examples are economic development rates and uncollectible accounts expenses. Economic development rates, as well as any costs for marketing and load retention, are not marginal costs. These programs are not needed for customer service and theoretically should pay for themselves by attracting or retaining loads or improving economic conditions in the area. Uncollectible accounts expenses are not marginal costs associated with current bill-paying customers and conceptually should not be included in marginal costs. This is a similar issue to the embedded cost issue, discussed in Section 12.2, regarding whether uncollectible accounts expenses are costs associated with present customers (direct assigned) or former customers (allocated by usage or revenue). California regulators removed uncollectible accounts expenses from marginal costs in 1989 (California Public Utilities Commission, 1989); the Nevada commission includes them (Public Utilities Commission of Nevada, 2002, p. 109). If uncollectible accounts are included, then late payment revenues must be treated consistently, by adding them to the distribution revenues to be allocated and subtracting them from the classes that pay them.

Lastly, a number of cost elements that are sometimes mistakenly classified as customer service do not fit a marginal cost analysis well, particularly if the programs are undertaken for public policy reasons. A cost undertaken for public policy reasons is not a marginal cost, even if it might theoretically vary with the number of customers. An energy efficiency program or demand response program is established by the state or regulators for policy reasons, theoretically to provide a cost-effective or environmentally preferred substitute for other investments and expenses. Subsidy programs for low-income customers are also established for policy reasons. Certain other programs are also policy-related, such as promoting solar energy, battery storage and electric vehicles; allowing customers to opt out of smart meters; and research and development programs. These are not marginal costs, and their allocation to customers outside of a marginal cost framework will be discussed in Chapter 23.

21.5 Illustrative Marginal Customer Costs

Tables 42 and 43 on the next pages illustrate a calculation of marginal customer costs using the NCO and rental methods, with a set of assumptions that are generally realistic but not tied to any specific utility.

Table 44 on Page 213 shows the impact of the choice of marginal customer cost methods on the MCRR of distribution and thus on the overall allocation of distribution costs. To illustrate this impact, there is also an assumption as to demand distribution costs. Costs for primary customers are assumed to be lower than for other classes largely because they do not need line transformers. In this example, the residential class has 41% of the MCRR for distribution costs with the rental method but 38.8% with the NCO method.

Table 42. Illustrative example of new-customer-only method for marginal customer costs

	Residential	Small commercial	Secondary large commercial	Primary industrial
Initial investment				
Service	$800	$1,200	$3,000	N/A
Meter	$200	$300	$3,000	$9,000
Total	$1,000	$1,500	$6,000	$9,000
Present value of revenue requirements (PVRR) factor				
Service	1.3	1.3	1.3	1.3
Meter	1.25	1.25	1.25	1.25
Investment with PVRR				
Service	$1,040	$1,560	$3,900	N/A
Meter	$250	$375	$3,750	$11,250
Total	$1,290	$1,935	$7,650	$11,250
New customers (% of system)	1%	1%	0.5%	0%
Replacements (% of system)				
Service	0.5%	0.5%	0.5%	0.5%
Meter	2%	2%	2%	2%
Marginal cost for new customers (investment with PVRR x new customer %)				
Service	$10.40	$15.60	$19.50	N/A
Meter	$2.50	$3.75	$18.75	N/A
Total	$12.90	$19.35	$38.25	N/A
Marginal cost for replacement (investment with PVRR x replacement %)				
Service	$5.20	$7.80	$19.50	N/A
Meter	$5.00	$7.50	$75.00	$225
Total	$10.20	$15.30	$94.50	$225
Total investment marginal cost for new and replacement customers				
Service	$15.60	$23.40	$39.00	N/A
Meter	$7.50	$11.25	$93.75	$225
Total	$23.10	$34.65	$132.75	$225
Customer operations and maintenance cost	$30	$50	$500	$700
Total marginal customer cost	$53.10	$84.65	$632.75	$925
Number of customers	1,000,000	100,000	10,000	1,000
Marginal cost revenue requirement for customer costs	$53,100,000	$8,465,000	$6,327,500	$925,000

Table 43. Illustrative example of rental method for marginal customer costs

	Residential	Small commercial	Secondary large commercial	Primary industrial
Initial investment				
Service	$800	$1,200	$3,000	N/A
Meter	$200	$300	$3,000	$9,000
Total	$1,000	$1,500	$6,000	$9,000
Real economic carrying charge rate				
Service	7%	7%	7%	7%
Meter	10%	10%	10%	10%
Annualized investment cost				
Service	$56	$84	$210	N/A
Meter	$20	$30	$300	$900
Total	$76	$114	$510	$900
Annual customer operations and maintenance cost	$30	$50	$500	$700
Total customer cost	$106	$164	$1,010	$1,600
Number of customers	1,000,000	100,000	10,000	1,000
Marginal cost revenue requirement for customer costs	$106,000,000	$16,400,000	$10,100,000	$1,600,000

Table 44. Illustrative comparison of rental versus new-customer-only method for overall distribution costs

	Residential	Small commercial	Secondary large commercial	Primary industrial
Marginal cost revenue requirement for customer costs				
Rental method	$106,000,000	$16,400,000	$10,100,000	$1,600,000
New-customer-only method	$53,100,000	$8,465,000	$6,327,500	$925,000
Marginal distribution demand cost per kW	$100	$110	$110	$75
Demand per customer (kWs)	4	25	250	2,000
Number of customers	1,000,000	100,000	10,000	1,000
Marginal cost revenue requirement for distribution demand costs	$400,000,000	$275,000,000	$275,000,000	$150,000,000
Results: Rental method				
Total distribution marginal cost revenue requirement	$506,000,000	$291,400,000	$285,100,000	$151,600,000
Share of distribution costs	41.0%	23.6%	23.1%	12.3%
Results: New-customer-only method				
Total distribution marginal cost revenue requirement	$453,100,000	$283,465,000	$281,327,500	$150,925,000
Share of distribution costs	38.8%	24.3%	24.1%	12.9%

Note: Based generally on California examples, except transformer part of demand cost. Marginal demand cost is higher in commercial classes than residential because residential has more customers per transformer. Demand is lower in industrial class because no transformers or secondary lines are included. Percentages may not add up to 100 because of rounding.

22. Administrative and General Costs in Marginal Cost of Service Studies

Both A&G expenses and general plant costs are typically considered "loaders" to marginal costs, applied to the generation, transmission and distribution functions. Fundamentally, at least some A&G expenses and general plant costs are marginal costs, though over varying time horizons and in varying amounts because of economies of scale in running a large corporation.

The NERA method in the 1970s used an extremely long-run marginal cost method for A&G costs. It developed loading factors based on what appears to be a fairly arbitrary mix of labor, O&M expenses and total plant for A&G expenses, and it allocated general plant based on other plant (other capital investments). As with other elements of the NERA method, the mismatch in time frames is a serious theoretical concern. One method of addressing this is to eliminate consideration of joint and common A&G costs from the marginal cost analysis. This leaves only short-run marginal A&G costs as a better match with short-run generation marginal costs.

Short-run marginal costs include at least workers' compensation and pensions and benefits associated with other marginal costs that are labor-related. Similarly, incentive pay, to the extent recorded to A&G accounts, is a short-run marginal cost assigned to labor. Property insurance is a plant-related marginal cost to the extent that the amount of insured property affects the premiums.

If longer-term A&G costs are included, one can either include all of them as variable in the long run with the size of the utility or recognize potential economies of scale, which would mean that only a portion of costs is marginal. The best example of an intermediate-term marginal cost is the human resources department, which varies with the size of the workforce. Other examples of costs that will vary with the size of the utility in the intermediate term are benefits administration, accounts payable, payroll processing and capital accounting. Over a longer period, portions of an even broader set of costs are variable. For example, executive salaries are related (though possibly not proportional) to the size of the company, as a larger company will have more executives and pay them more (Marcus, 2010a, pp. 90-93 and Exhibit WBM-18). Other examples relate to buildings and other general plant items. A utility with fewer workers will own, rent and maintain less building space and have fewer vehicles and tools.

Recently a number of utilities, following the FERC method of unbundling transmission, have allocated both A&G expenses and general plant costs (using a long-run marginal cost basis) based on labor with the exception of (1) property insurance, which is based on plant, and (2) franchise fees based on revenue. The labor allocation method for A&G expenses tends to be less favorable to small customers than the plant-based method, but it has analytical merit. Key issues here are (1) ensuring that specific elements of A&G expenses are truly recurring marginal costs and (2) whether a given cost should be functionalized differently among generation, transmission and distribution. This can be as simple as, for example, removing a large one-time fire claim (which has no relationship to any cost drivers) from a utility's recorded A&G expenses and removing nuclear insurance from liability insurance allocated by company labor when the company had no labor costs at a jointly owned nuclear plant (Jones and Marcus, 2016, pp. 20-21). Or it can involve a more complex analysis of which specific A&G costs are marginal, an exercise Southern California Gas Co. undertook in its gas marginal cost studies (Chaudhury, 2015, pp. 21-22).

23. Public Policy Programs

There are a number of costs related to public policy decisions by state regulators that generally should not be considered marginal costs. Consideration should be given to allocating these costs separately from marginal costs. Many states have explicit cost allocations for public policy or energy efficiency costs that are separate from base rates or distribution rates. In California, energy efficiency costs are largely, though not entirely, allocated in proportion to total system revenues, with generation revenues imputed to customers who do not receive generation service from the utility so that direct access and community choice aggregation customers do not pay lower rates for public purpose programs than bundled customers with otherwise similar characteristics.[231] California allocates low-income rate subsidies in equal cents per kWh to all customers except municipal streetlights and those customers receiving the subsidies.[232]

However, some policy-oriented costs related to demand response programs and other items have been included in distribution costs, so that all customers, including those who may purchase generation from others besides the utility, can be required to pay for them. In these cases, the allocation of a cost such as demand response by an allocator such as a distribution equal percentage of marginal cost (EPMC) creates concerns. If costs of a demand response program that avoids generation are allocated by distribution EPMC (or even total EPMC), residential customers might be better off if the utility instead built generation of equivalent or, in some cases, higher cost, even if society would be worse off — because a smaller portion of the higher cost would be allocated to them. Even if a demand response cost is designed to avoid some T&D, the demand response measure generally will also reduce the need for generation capacity.

One framework used by consumer advocates in California applies different approaches to different subsets of public policy costs. It allocates the costs of direct programs that provide generation in distribution rates (e.g., interruptible and load management rate credits) by EPMC of generation (with generation marginal costs imputed to those not served by the utility). At the same time, it allocates programs that provide more broad public benefits (e.g., electric vehicle programs, research and development) or that create infrastructure to enable demand response (e.g., computer systems, the portion of AMI costs in excess of those that are cost-effective operationally for the distribution system) based on the equal percentage of revenue method discussed above for energy efficiency.

231 This method was essentially codified in A.B. 1890, California's restructuring legislation of 1996. Although the specifics of that legislation no longer apply, relatively similar methods have been used throughout the last two decades in a number of settled cases.

232 California Public Utilities Code § 327(a)(7): "For electrical corporations and for public utilities that are both electrical corporations and gas corporations, allocate the costs of the CARE program on an equal cents per kilowatt hour or equal cents per therm basis to all classes of customers that were subject to the surcharge that funded the program on January 1, 2008."

24. Reconciling Marginal Costs to Embedded Costs

It is only happenstance if marginal costs and embedded costs produce the same revenue. This raises questions as to how to reconcile these items. The most common method allocates embedded cost revenue requirements in the same proportion that marginal costs are allocated. This is typically called the equal percentage of marginal cost method but may also be known as equiproportional.

There are two types of EPMC allocation. The first allocates the entire revenue requirement by the entire marginal cost revenue responsibility, called total EPMC allocation.[233] This method was used in both California and Nevada through the 1990s. Under this method, if generation marginal costs are low (because of excess capacity, renewable penetration, low gas prices or other reasons), more of the system costs are allocated based on distribution costs, which are allocated more heavily to small customers. The result is problematic for small consumers. This was particularly evident in California, where high costs in the 1980s — created by power purchase contracts required under PURPA and additions of nuclear power — were heavily allocated based on distribution costs because of excess capacity, low system incremental heat rates due to large amounts of baseload power, and falling gas prices that did not reflect the expectation at the time the excess capacity was being constructed.

A second problem with this total EPMC allocation method is that it does not work well in quasi-competitive markets. If some customers have market options to acquire generation and others do not, as in California and Nevada, using an EPMC method based on total marginal costs could distort competitive choices by setting generation rates based on a mix of generation, transmission and distribution marginal costs. As a result, both of these states now use an EPMC allocation by function. They separately allocate generation, transmission (in Nevada; California transmission used by investor-owned utilities is entirely under FERC jurisdiction) and distribution based on EPMC.[234]

The other less used approach for reconciling marginal costs to embedded costs is an economic approach known as Ramsey pricing and the resulting inverse elasticity rule.[235] Under this construct, any deviation from marginal costs creates an economic distortion. Advocates of this approach would reconcile marginal costs to embedded costs in the "least distortive" manner. At a high level this is reasonable, but there are many disputes about which choice is least distortive. Many advocates of this approach take a narrow view of societal costs and externalities and argue that the responsiveness of customer classes with respect to higher or lower costs — a concept known as elasticity of demand — is the key criterion. Relative elasticity of demand between rate classes, and between different rate elements for each rate class, is difficult to measure. Some advocates of the Ramsey pricing approach assume that residential customers are less responsive to changes in cost in the short term, particularly with respect to changes in the customer charge. But according to these advocates, if embedded costs are higher than the MCRR, then this leads to a larger share of costs being borne by residential customers, with those costs being recovered through higher customer charges for residential customers. These underlying assumptions may not have been true historically, but changing circumstances may weigh

233 The use of EPMC as a whole in California was first clearly adopted in 1986 (California Public Utilities Commission, 1986, pp. 636-646).

234 The unbundling of revenue allocation in California by function after the incomplete adoption of utility restructuring is discussed in Schichtl (2002). The functionalization of EPMC in Nevada is found in Public Utilities Commission of Nevada (2007, pp. 162-167).

235 This method was named after Frank B. Ramsey, who found this result in the context of taxation. Later, Marcel Boiteux applied the rule to natural monopolies in declining cost industries.

even more heavily against this approach in the future. If externalities are incorporated, then in many circumstances per-kWh rates are actually lower than the full societal marginal cost of consumption — meaning it would be socially efficient to classify incremental costs as energy-related. Full incorporation of externalities, in fact, argues for a differential approach depending on whether the MCRR is lower or higher than embedded costs, classifying any incremental costs as energy-related for inclusion in kWh rates while classifying any excess revenue as customer-related to provide a reduction in customer charges.

In addition, certain types of multifamily buildings often face a choice between master metering and individual meters. This choice affects the number of customers and overall customer charge revenue but has almost no effect on system cost other than meters and billing. The declining cost of storage and solar may enable growing numbers of customers to disconnect entirely from the grid as well. The experience in the cable television and telephone industries shows how people are willing to "cut the cord" to rely on nonmonopoly service providers. Lastly, even if the underlying claims from certain advocates of Ramsey pricing are correct, there are significant equity issues between classes at stake in the allocation of additional costs solely to the residential class. Similarly, using Ramsey pricing to pass those costs on through customer charges raises significant equity issues within the residential class, disproportionately affecting small users.[236]

236 It could be the case that lower-income customers have a more elastic demand to pay for electric service if prices are increased because of limited ability to pay.

25. Cutting-Edge Marginal Cost Approaches

It is important to sketch out a new paradigm for marginal costs, even though many of the calculations on which it could be constructed have not been developed.

The NERA method for calculating marginal costs, particularly for generation, becomes less sustainable as the utility systems move toward major technological change and reductions in carbon. While the effect may be different in different regions of the country, the short-term avoided energy cost will reflect diminishing variable costs to the extent that natural gas is replaced with renewables and storage. Capacity costs may be moving toward batteries given that renewable integration can be achieved better with storage resources that can both use overgeneration and provide ramping and integration more effectively than fossil-fueled plants that do nothing about overgeneration. Thus, it is important to at least sketch out a new paradigm for marginal costs, even though many of the calculations on which it could be constructed have not been developed yet or integrated into a whole.

25.1 Total Service Long-Run Incremental Cost

The basic theory presented here is the total system long-run incremental cost method that was developed in the telecommunications industry during its period of rapid technological change before deregulation. Under this method, all costs are variable but may be very different from historical costs. This is important when examining the generation system in particular, because the optimal system going forward is likely to have very few traditional variable costs.

The TSLRIC is theoretically defined as the total cost of building and operating an optimal new system to serve the current load with changes that can be reasonably foreseen and changes to reflect environmental priorities (e.g., additional efficiency and demand response, changes to electrification for purposes of decarbonizing existing fossil fuel end uses and development of more loads with storage or other controls). The system will be different from the current system in a number of ways. The theory is that it will be optimally sized with optimal technology, which should in most cases reduce costs (or at least societal costs reflecting environmental constraints) relative to current technology — although that may not always be true. However, the system would also be built at current construction costs, so it could be more expensive in that regard. Since TSLRIC represents an optimal system, it removes one of the key problems of the NERA method, which can disproportionately assign excess capacity to specific customer classes if not undertaken carefully to remove the excess capacity.

Although the theory is relatively easy to state, it has not been implemented for an electric utility, and the data to implement it will need to be collected and analyzed.
To make this calculation, one needs to start with the cost of the existing system. This is then adjusted for inflation since the time when it was built, yielding what is usually referred to as "replacement cost new." But a TSLRIC study goes beyond simply a study of the replacement cost of the system as it exists today. Other sources of data should be acquired for resources whose costs are declining due to technological change and data availability. From that point, one examines the changes in the generation resource mix to move it toward optimality. Substitution of storage or other DERs for upstream generation and transmission may reduce TSLRIC costs. A complex engineering analysis would also be required to review the magnitude of the cost-decreasing and cost-increasing drivers for transmission and distribution costs, which are likely to be different by utility. The discussion below outlines qualitative issues relating to the cost

changes that would result from using a system constructed under TSLRIC.

25.1.1 Generation

Without full quantification, an optimal system 15 to 20 years out will contain considerably more wind generation, solar generation, possibly some other renewable generation and more storage than the current system. The mix of solar and wind generation is likely to be region-specific, depending on available resources that can be economically brought to market. Some storage could be centralized, providing generation for peaking, ramping and renewable integration. At the grid level, storage could be related to batteries, compressed air and pumped hydro, as well as the load-related operations of large water projects (e.g., hydroelectric capacity and flexible pumping loads and storage associated with large water supply projects). The question of black start capability of storage resources may need to be addressed because, if storage can provide this capability, it may supplant the need for certain gas-fired resources.

Storage could be decentralized, also serving to reduce the need to build distribution capacity while serving the distribution system with greater reliability in addition to G&T displacement. At the decentralized level, batteries would be an option, but so would end-user storage such as controllable water heaters (which would have significant benefits for dealing with ramp), thermal energy storage to supplant peak air conditioning, and use of existing or new water storage to control timing of pumping and delivery by local water agencies and irrigators. This storage is a joint product that must be functionalized among generation, distribution and possibly transmission.

Controls on electric vehicle charging — to keep them out of peak periods, avoid distribution overloads, preferentially charge to mitigate ramp and possibly reverse flows (vehicle to grid) — could also create flexibility, since there would be little or no resource costs except controls (incremental changes in costs of charging and discharging only). These controls are installed at the end user level but may be critical to reduce generation and distribution costs in an optimal system and as such would be part of TSLRIC.

Other demand response programs beyond traditional programs (such as interruptible industrials and air conditioner cycling) likely would become cost-effective as part of an optimal system. Examples include smart appliances that would run discretionary loads such as washing, drying or dishwashing at times when the loads match system needs, and variable-speed drives for heating, ventilation and air conditioning systems that could both save energy and respond automatically to peak or ramp conditions. These also may be part of TSLRIC, functionalized among generation, transmission and distribution as joint products.

Most existing conventional hydro and pumped storage resources probably would remain part of an optimal system, although the timing of their usage may change from the current system. In part, even under TSLRIC, it is not reasonable to ignore high decommissioning costs that can be avoided by keeping them in operation. More importantly, hydro resources with storage also provide energy at zero incremental costs, as well as ancillary services and significant amounts of flexibility to the grid. These resources may be devalued rather than being included at full replacement cost to recognize that their continued operation depends in part on avoiding the costs of removing them — which is generally not considered in a TSLRIC environment. However, some smaller resources would be closed, particularly run-of-river plants and those in areas where there are significant environmental impacts. At current and projected costs (considering those related to capital, operations and emissions), coal and traditional nuclear units[237] likely would not be part of the new optimal system under TSLRIC.

The role of natural gas-fired generation for reliability and bulk energy generation in an optimal system that recognizes carbon constraints is a large question. In all likelihood, some of the most efficient gas generating units would remain for a significant period, although the amount of energy they produce could be considerably less than at present. Gas plants could include:

- CHP, which has very high efficiency and uses thermal energy to produce steam for industrial processes or chilled water to displace air conditioning loads.

237 Consider the abandonment of South Carolina Electric and Gas Co.'s Summer Nuclear Station and the cost overruns at Georgia Power's Vogtle units 2 and 3, which cost $23 billion — or more than $10,000 per kW (Ondieki, 2017).

- Combined cycle generation designed for flexible use that could also make up for any shortages in bulk energy if adverse weather conditions reduce output from hydro and renewables.
- Potentially, gas turbine peakers. The modern gas turbine supplanted less-efficient older gas-fired steam units. But storage and demand response are likely to make even modern gas turbines less economic, particularly for reserves, needle peak use and ramping.[238] Nevertheless, in some places, particularly where gas turbines are considerably cheaper than combined cycle units and where other flexible resources (such as hydro) are not widely available, there may be a dispatch range (for example, a 10% to 20% capacity factor) where gas turbines might be economic in an optimal system.

For any fossil generation, to the extent not otherwise internalized, a carbon adder based on residual damage or mitigation costs would be included under TSLRIC, but much of the TSLRIC system is being rebuilt to optimize for the need to reduce carbon emissions as well as for financial costs.

25.1.2 Transmission

Assuming no major technological advances (e.g., superconductors), some changes in transmission from the current system would arise from changing generation patterns. Long-distance transmission from existing coal and nuclear stations may no longer be part of an optimal system, but long-distance transmission from distant wind regions may replace it as a significant factor, either because of new construction or wheeling costs.[239] Interties would likely remain, although there may be more bidirectional power, and their role may be clearing renewable surpluses across wide regions. These transmission facilities for delivery of bulk energy, explicitly excluded from the NERA method, probably would be allocated over hours of use — making them energy-related, since they are not constructed for peak loads.

There may be other efficiencies associated with both better controls and with the possible use of strategically located storage devices if cheaper than both transmission lines and conventional RMR gas-fired generation. PG&E's use of batteries to displace an RMR contract in an area south of San Jose (discussed in Section 18.3) suggests the potential of this outcome. It is also possible that a further analysis of a more optimal network of transmission lines may reveal significant portions of those lines are, in fact, related to off-peak use or contingencies that could occur at nonpeak times and should thus be spread over more than peak hours.

25.1.3 Shared Distribution

The whole distribution system would become part of TSLRIC, instead of just the narrowly defined portions where the NERA method suggests investments are needed to serve increases in demand. The optimal distribution system is likely to need less capacity and to serve load more reliably and with fewer losses than the current system, because of technologies such as automatic switching and integrated volt/VAR controls — which would reduce costs — and because energy efficiency (particularly related to space conditioning), decentralized storage, demand response and controls on electric vehicles could reduce distribution peaks.

There are likely to be customers for whom usage is so low that they are better served by DERs than by a grid. They will include many rural customers (particularly in areas with high potential fire danger) but also small loads in an urban area. Solar-powered school crossing signals are being installed today, simply because the cost of connecting to the grid exceeds the cost of the distributed energy system. Other applications using low-wattage LED lights (e.g., traffic signals and remote streetlights) may ultimately also find a distributed alternative to be cheaper than grid service. Factoring this into a TSLRIC study will ensure that low-use customers are not assigned costs that will not benefit them economically.

Distribution is also likely to be bidirectional at least in some places, particularly if whole neighborhoods are served with distributed solar (or solar plus storage) resources. This change may require more expensive control systems in some

238 In 2018, NV Energy executed contracts for four-hour battery storage at a cost of $73 per kW-year, less than the carrying cost plus nondispatch O&M for a peaker (Bade, 2018).

239 For example, capacity freed up on transmission lines bringing coal-fired electricity from Four Corners to Southern California Edison is now being used to deliver wind energy from New Mexico. (Southern California Edison, 2015, p. 4).

places but is also likely to have a net effect of economizing on system sizing. Some primary distribution feeders (along with service lines and transformers) may need to be reconstructed if neighborhoods are converted from gas to electric space heating or if electric vehicles become ubiquitous, but those costs would be spread over more kWhs of load. Beneficial electrification of heating and transportation could increase total distribution costs, but because these technologies add energy loads, the costs per kWh may be stable or decline, and the amount of winter peaking load is likely to increase.

However, costs can increase from other aspects of the optimal distribution system. More of the optimal system is likely to be underground in urban areas, increasing system capital costs. Although overhead wires are cheaper, they also have nonmonetary costs related to worse aesthetics, poorer reliability (particularly in areas subject to ice storms and tropical storms) and to some extent worse safety (fires, downed wires). There would be some cost offset because the oldest and least reliable underground technologies that are currently being replaced at significant cost would have been supplanted, thereby reducing TSLRIC maintenance and replacement costs compared with current costs. Urban vegetation management costs would also be reduced in a system with more undergrounding. The overall costs of increased underground service (even after netting out the relevant costs avoided, such as maintenance, replacement of aging lines and vegetation management) likely would still be higher than current costs.

The optimal distribution grid is likely to have other cost-increasing features. It will need more resilience against natural disasters such as hurricanes, more patrols and maintenance to prevent fires, and costlier and more extensive vegetation management. It will also incur costs for protection against stronger winds, dealing with safety hazards from pole overloading by both electric utilities and communications companies, and possibly undergrounding in some remote areas to prevent outages and fires.

One potential outcome in the Western U.S. may even be that significant parts of the grid routinely begin to receive interruptible service to prevent wildfires. Even more remote portions of the grid serving few customers in areas with high fire danger may be completely abandoned. In essence, those parts of the system could be turned back to individual customers who use solar and storage to serve their loads and establish small microgrids. They may possibly be some of the last customers with fossil fuels (propane or compressed natural gas) as a source for meeting relatively large energy loads such as space and water heating in a mainly decarbonized system.

25.1.4 Customer Connection, Billing and Service Costs

The design of customer connection equipment may not change greatly, except for replacement of urban overhead lines with underground equipment and possibly some advances in controls that can optimize transformer capacity for small customers. As noted earlier, some service lines and transformers may need to be resized if neighborhoods are converted from gas to electric space heating or electric vehicles become ubiquitous. As with the current system, costs of advanced metering would need to be divided between the pure connection and billing function and the costs of other services that AMI provides (to reduce grid costs and to provide platforms for demand response and storage behind the meter).

Customer accounting and service O&M will be reduced due to the continuation of greater productivity from internet and interactive voice response systems and the prevalence of cheaper methods of receiving and paying bills that were discussed in Section 21.4. These items have been increasing productivity for the last decade and are likely to continue to do so.

25.2 Hourly Marginal Cost Methods

Although the hourly marginal cost method has not been explicitly used (a variant is used in Nevada), the Energy and Environmental Economics long-run marginal cost study points to how such a method could be used. Rather than dividing costs into demand and energy costs and allocating by kWs, E3 assigns its various types of avoided costs to individual hours so that specific energy efficiency, demand response and distributed generation costs could be measured against the hourly costs given their operational patterns. When costs are assigned to hours, the allocation to classes can be based on customer loads in those hours without calling the costs "demand" or "energy" costs. As with hourly allocation embedded cost methods, this may be an approach that will serve the cost analyst as the utility system evolves to include widespread renewable and distributed resources.

To convert the marginal costs calculated using a variant of the NERA method into hourly costs, and after considering the E3 hourly cost calculation, the following method could be used. This method still has some of the potential drawbacks of the NERA method discussed in detail above (possible mismatches in short-run and long-run analysis, failure to consider certain plant such as transmission interties, ambiguous treatment of replacement equipment, etc.). The NERA approach is also a fundamentally peak-oriented method, as opposed to the methods based on hours of use of capacity suggested in Chapter 17. Nevertheless, with some modification, it can be amenable to hourly calculations.

25.2.1 Energy and Generation

Energy costs can be calculated on a time period basis, as in Oregon or California. Otherwise, energy costs can be calculated on an hourly basis, as in Nevada, and aggregated into time periods based on hourly loads (including losses) by each class in each time period. Generation capacity costs need to be originally calculated in dollars per kW of capacity and divided between peaking capacity and other capacity needs (e.g., ramp) in ways described in Section 19.3. The peaking costs would be assigned to a subset of hours using methodologies such as loss-of-energy expectation, PCAF, loads or load differentials in largest ramp periods, or other multihour methods. Costs in each hour would then be calculated in cents per kWh and multiplied by the loads in each hour (including losses). The hourly costs can be aggregated into time periods. Consideration should be given to the establishment of a super-peak period for hourly cost allocation containing the highest peak-related costs based on loss-of-energy expectation or PCAF allocations to encourage the use of short-term resources such as demand response. If ramp costs are calculated, they could largely be based on storage operations and could have negative capacity costs in hours when storage is charging immediately before a ramp and positive capacity costs from the beginning of the ramp through the daily peak and shortly afterward.

25.2.2 Transmission and Shared Distribution

For transmission and distribution costs (except possibly for distribution costs for new business, including primary lines installed to connect new customers and transformers), a method that skips the dollars-per-kW step and goes directly to total dollars per hour has advantages. It avoids the significant problems associated with mismatches of kWs of capacity (calculated based on extreme weather peak loads or size of equipment that is added) and kWs of load (calculated based on a smaller number of kWs such as PCAF or a peak or diversified demand); see Appendix C. This also provides a clearer path toward design of TOU pricing. If a figure in cents per kWh is needed in an hour or time period, total dollars can be divided by the loads in each hour. Such an allocation method would need to be disaggregated by voltage (transmission if not FERC jurisdictional, possibly subtransmission, distribution). Additionally, a disaggregation at each voltage between substations and circuits would improve an hourly calculation because substations and circuits may have different time patterns of usage and cost causation.

For each component (excluding the transmission components for utilities with fully FERC jurisdictional transmission), the total investment in capacity-related equipment including automation and controls — unlike the NERA method, which excludes them — would be calculated in real dollars and averaged over a period such as 10 years. This should perhaps include both forward-looking and historical data as with the NERA method. The costs should then be annualized using an RECC and with O&M and possibly replacements added (in real dollars per year). The O&M and replacement costs would be based on either averaged costs or forward-looking costs if changes from the average have been observed or are expected.

Substation capacity needs are generally oriented to the peak loads of the equipment, although they are also related to the duration of heavy energy use, suggesting a broader allocation than a single coincident peak. An allocation of total dollar costs to time periods consistent with the NERA method's emphasis on capacity could be based on some hybrid of the percentage of kVA of substation peaks in each season and time period and a PCAF, which has an energy component because all loads in excess of 80% of the peak are assigned some capacity value. The PCAF could be set differently for summer and winter peaking kVA if applicable. For rate design purposes, a super-peak period could also be carved out that recognizes stress on components and high marginal line losses during extreme loads.

Transmission and subtransmission line marginal capacity under the NERA method involves a highly networked system, where at least some of the installed capacity is needed to meet contingencies that may occur at times other than during peak hours. The hourly causation and allocation of costs is likely to require further analysis that has not yet been conducted. But it could be some mix of peak loads (i.e., PCAF) and hourly loads (weighted into time periods when contingencies are most likely to occur to the extent possible).

Distribution substations are generally oriented to diversified peak loads on the equipment while also being related to the duration of energy use and should be allocated to hours in a manner like the allocation of transmission substations. Distribution lines are more radial in nature, although switching among feeders has been installed in some places, and more automation and volt/VAR controls are likely to cause distribution systems to become more networked. The cost causation for distribution line capacity has a peak-oriented component — which is likely to increase as the system networking and switching increases — and a component related to individual feeder peak loads, which is likely to decline. To allocate these costs to hours, one could start with a cost component for specific lines that would be directly assigned based on the individual peak of customers who are very large in relation to feeder sizes (i.e., customers over a particular MW size or a high percentage of the feeder's peak load). Remaining costs could be allocated to hours based on a mix of PCAF or top hours, a component based on the timing of individual feeder peaks (taking into account differences in residential and commercial load patterns) and a base load to all hours. For cost allocation, the hourly loads for feeder peaks could segregate the residential and commercial loads into different hours. If large customers are directly assigned costs, they would not be allocated any of the hourly costs.

New business distribution lines could be part of distribution circuits or could be segregated into a separate cost item for allocation. If new business lines and line transformers are separated from other distribution costs, the costs could be calculated in dollars per kW using a method with a demand measure such as changes in the demand at the final line transformer[240] (which reflects diversity for those customers sharing transformers). These costs can then be allocated to hours within each class based partly on class peak load characteristics (e.g., assigning more costs to residential customers in summer evening hours or to commercial customers during summer afternoons) and partly to additional hours to reflect that transformer performance is degraded if more energy is used in high-load (nonpeak) hours, as discussed in Section 5.1. A class allocation based on loads at the transformer would reflect that these very localized costs have some relationship to the customer's own demand (diversified to the transformer). Some utilities may have a small secondary distribution marginal capacity component reflecting that capacity may need to be added to networked secondary systems. This cost, if applicable, could be treated similarly to new business and line transformer costs, assigned in dollars per kW based on demand at the final line transformer and assigned to classes on the secondary system in the same way as line transformers.

O&M costs for substations and circuits generally should be allocated in the same way as the plant, except that costs of vegetation management and various periodic patrols and inspections should be assigned to all hours because they are not caused by peak loads.

If T&D replacement costs are included as recommended in Chapter 20, the costs should be allocated to hours either in a manner like the underlying allocation for plant of each type or based on all hours, reflecting that replacements are not based on peak demand. Some mix of the two methods may also be used.

240 With an allocation to primary voltage customers based on maximum demand but excluding transformer costs.

26. Summary of Recommendations for Marginal Cost of Service Studies

This chapter provides recommendations on two sets of issues: how to make incremental improvements to the predominantly used NERA method and how to work toward developing an hourly TSLRIC method, which has not yet been implemented.

26.1 Improving Marginal Cost Methods

Nine key items are distilled from Part IV as to how to improve marginal cost methods from the NERA method.

1. Analyze whether demand response can provide relief for the highest 20 to 50 hours of system load more cost-effectively than supply options, and substitute these costs for peak-hour costing if they are available and cost-effective.
2. Analyze whether grid-sized batteries are the least-cost capacity resource in the near term, instead of combustion turbine peakers, to meet the highest few hundred hours of system load — recognizing that they may take on a different role in the long term as systems become more heavily reliant on variable renewable generation. This is particularly important if reliability has a grid integration or ramping function as well as a peaking function in the relevant jurisdiction, because a battery can reduce ramp approximately twice as much as a generator of the same size and can smooth intermittent resource output better than a fossil-fueled plant.
3. Move toward long-run incremental costs for generation containing less carbon as a first step toward the TSLRIC method. Oregon uses 75% combined cycle and 25% solar in its long-run incremental cost. To the extent that it can be reasonably justified, a decarbonized long-run incremental cost would have storage for capacity, more renewables and less gas.
4. If the NERA-style short-run energy and generation capacity cost methods are used in the relevant jurisdiction, use a longer period of time for analyzing marginal energy costs than one to six years to deal with the mix of short-run and long-run costs currently used. Also ensure that carbon costs are included and a renewable portfolio standard adder is used if relevant to the jurisdiction. And examine whether pure capacity purchased from the market is cheaper than either a combustion turbine or battery for near-term application.
5. Make the definition of marginal costs more expansive for transmission and distribution to include automation, controls and other investments in avoiding capacity or increasing reliability, and consider including replacement costs.
6. Use the NCO method of calculating marginal customer costs. If replacement is included for any assets, a replacement rate should be based on actual experience, which would typically be less often than the accounting lifetime suggests.
7. Functionalize marginal costs in revenue reconciliation; use EPMC by function, not in total.
8. If demand costs are used, make sure that kWs used to calculate marginal costs and kWs used to allocate them are harmonized.
9. To the extent feasible, use an hourly method, such as the one E3 developed, to assign costs to hours and then to customer class loads. This avoids the need to separate costs into the demand and energy classification.

26.2 Moving Toward Broader Reform

TSLRIC will require both vision and research to be implemented for all utility functions. How a TSLRIC approach might look different from simply using replacement cost new for existing facilities was sketched out in Section 25.1.

The first place where a TSLRIC approach could be used is for generation, where it could be built up from a lower-carbon long-run incremental cost. Other resources may also be available to assist in constructing the TSLRIC of generation. They include the low-carbon grid study for the Western grid and similar studies that build out potential future resource plans (Brinkman, Jorgenson, Ehlen and Caldwell, 2016, and Marcus, 2016). This is a data-intensive approach that will require envisioning and costing out future systems and determining the resilience of the cost estimates to various assumptions. TSLRIC for generation probably suggests starting with a "cost by hours of use" approach, since there is only a limited amount of resources with fossil fuel that may not be dispatched in all hours. This means that price shapes based on short-run marginal cost may no longer make sense. This method would end up giving batteries and storage negative energy costs when they are charging and positive costs when discharging. Distributed generation would require functionalization.

Developing TSLRIC for transmission and distribution would require considerable amounts of engineering analysis to determine how the various cost drivers would work when developing a more optimal system and would likely involve a longer process.

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Part V:

After the Cost of Service Study

27. Using Study Results to Allocate the Revenue Requirement

Ultimately, the purpose of a cost of service study is to inform utility regulators about the relative contribution to costs by the various customer classes as one element in the decision on how to apportion the revenue requirement among classes. In most states, regulators have a great deal of discretion about how they use the results of cost allocation studies. Therefore, the way the results are presented is important because the regulators will want to see important impacts clearly to use their time efficiently.

Embedded cost of service studies and marginal cost of service studies approach this very differently, and we discuss each separately in this chapter. After that, we discuss approaches regulators use to implement, or diverge from, the results of these studies.

27.1 Role of the Regulator Versus Role of the Analyst

The role of the regulator is different from that of the analyst. Regulators typically are appointed or elected into the position based upon their broad perspectives of what "fair, just and reasonable" means in the context of utility regulation and pricing. These perspectives are necessarily subjective.

The analyst, on the other hand, may be tempted to work on a strictly scientific and mathematical basis. This may not adequately serve the needs of the regulator, who may need the analysis to take note of public policy goals, economic conditions in the service territory and other factors.

In the simplest terms, the regulator may need a range of reasonable options for cost allocation and for rate design, based on a range of reasonable analytical options, not a single recommendation based on a single framework or approach. The analyst must be prepared to develop more than one cost allocation study, based on more than one analytical approach, and let the regulator consider the principles guiding each study. The analyst must be prepared to develop multiple approaches to rate design, all sharing the same goals of overall revenue recovery and efficient forward-looking pricing.

27.2 Presenting Embedded Cost of Service Study Results

Embedded cost of service studies typically include conclusions regarding the relative margin to the utility from each customer class. Relative margin is a measure of profitability, based on the revenues, expenses and rate base allocated to each class.[241] Class profitability is often presented in the following forms:

1. Calculated rate of return on rate base (expressed both by class and for the total utility):

   $$\text{rate of return} = \frac{\text{allocated annual operating income}}{\text{allocated rate base}}$$

   Where allocated annual operating income = annual revenues – annual allocated expenses

2. Calculated utility profit margin (expressed both by class and for the total utility):

   $$\text{profit margin} = \frac{\text{annual revenues}}{\text{annual allocated expenses}} - 1$$

3. Ratio of class revenue to total class-allocated costs:

   $$\text{revenue ratio} = \frac{\text{revenues}}{\text{allocated expenses + allocated return}}$$

   Where allocated return = allocated rate base x allowed rate of return

4. Revenue shortfall:

   shortfall = (allocated return + allocated expenses) – current revenues

5. Percentage increase required for equal rate of return:

   $$\text{increase for equal rate of return} = \frac{\text{shortfall}}{\text{revenues}}$$

Table 45 on the next page shows an illustrative example of the computation of these measures.

241 These computations may use historical revenues and costs or projected revenues and costs.

Table 45. Computing class rate of return in an embedded cost study

	Total	Residential	Small (up to 20 kWs)	Medium (20 to 250 kWs)	Large (more than 250 kWs)	Large primary	Other
Revenues	$117,760,688	$28,116,419	$8,342,138	$26,156,458	$38,730,796	$15,134,759	$1,280,117
Allocated expenses	$112,438,805	$28,297,246	$8,997,362	$23,807,377	$35,927,265	$14,280,041	$1,129,515
Operating income	$5,321,883	-$180,827	-$655,223	$2,349,081	$2,803,532	$854,718	$150,603
Allocated rate base	$87,878,094	$24,935,855	$8,339,503	$18,481,728	$26,069,711	$9,399,629	$651,667
Allocated return	**$5,321,883**	**$1,510,111**	**$505,039**	**$1,119,251**	**$1,578,778**	**$569,240**	**$39,465**
Rate of return	6.06%	-0.73%	-7.86%	12.71%	10.75%	9.09%	23.11%
Profit margin	4.52%	-0.65%	-7.82%	8.94%	7.21%	5.62%	13.33%
Revenue-cost ratio	100.00%	94.33%	87.79%	104.93%	103.27%	101.92%	109.51%
Revenue shortfall (or surplus)		$1,690,938	$1,160,262	($1,229,831)	($1,224,754)	($285,478)	($111,138)
Percentage increase for equal rate of return		6.01%	13.91%	-4.70%	-3.16%	-1.89%	-8.68%

Note: Independent rounding may affect results of calculations.

To the extent that the results of the cost of service study are reliable, the class rates of return indicate which classes are paying more or less than the average return. In the example in Table 45, the rate of return results show that the utility is earning less than the average return from the residential class and the small general service class and more than average from the other classes. These class rate of return results do not provide much information about the size of the revenue shift that would produce equal rates of return (or any class-specific differential return requirement), or whether a negative rate of return represents a very serious situation.

The profit margin, while commonly used in many industries, ignores the return on capital. The revenue-cost ratio provides a more intuitive metric. The most useful results may be the revenue shortfall and the increase required to produce class return equal to the system average return.

These metrics show a very different picture of interclass equity. The residential class may be providing a negative rate of return, -0.73% in Table 45, but its revenues are equal to 94.33% of the system revenue requirement. Because of uncertainties in sampled load data, variation in load patterns among years and the difficulty of defining the causation of many costs, regulators define a "range of reasonableness" of one or more of the profitability metrics. For example, if the regulator considered reasonable the range of revenue-cost ratio from 93% to 107%, it is possible a regulator might find that the residential class is producing a reasonable level of revenue but that small general service customers should be paying a somewhat higher share of system costs than 87.79% and the "other" class (which might be mostly street lighting) should be paying somewhat less than 109.51%.

The cost allocation process usually assumes that all classes and all assets impose the same cost of capital. The results in Table 45 reflect that assumption, effectively stating that an equal return is the goal. In some cases, the regulator may determine that different customer classes impose different financing costs in percentage terms — for example, to reflect the higher undiversifiable risks of serving industrial loads through the economic cycle. In addition, some assets are riskier than others; generation is generally riskier than T&D, while nuclear and coal generation are often regarded as being riskier than other generation. In this situation, the cost of service study could be modified to reflect the differential risks (different required rates of return can be applied to different classes of customers or different categories of utility plant). Or the cost of service study results could be presented in a manner that allows the user to compare the achieved return to the class target return.

To summarize, presenting embedded cost of service study results in multiple ways is often helpful to regulators. The revenue-cost ratio is probably the easiest way for regulators to understand and use the results of cost of service studies in determining the fair, just and reasonable apportionment of costs. It is important to note that the result of this allocation process is to determine a level of revenue that the regulator deems cost-related. The regulator will often apply other non-cost criteria to establish the level of revenue that each customer class will pay.

27.3 Presenting Marginal Cost of Service Study Results

Marginal cost of service studies reach a very different set of conclusions than embedded cost of service studies. While an embedded cost of service study divides up the allowed revenue requirement among classes, a marginal cost of service study measures (over a short-, intermediate- or long-run time frame) the costs that would change as customer count and usage change.

A marginal cost of service study produces a cost for each increment of service: the cost of connecting additional customers, peak capacity at different levels of the system and energy costs by time period. These can be multiplied by customer usage to generate a marginal cost revenue requirement for each class. Table 46 shows an illustrative marginal unit cost result.

Table 46. Illustrative marginal cost results by element

	Units	Cost per unit
Customer connection	Dollars per year	$80
Secondary distribution	Dollars per kW	$40
Primary distribution	Dollars per kW	$80
Transmission	Dollars per kW	$50
Generation capacity	Dollars per kW	$100
Energy by time period		
On-peak	Dollars per kWh	$0.10
Midpeak	Dollars per kWh	$0.07
Off-peak	Dollars per kWh	$0.05

Table 47 shows load research data for an illustrative utility system with three classes with identical kWh consumption but different per-customer usage and very different load shapes. The residential class and secondary commercial class both take power at secondary voltages, but the secondary commercial class has a more peak-oriented usage and 10 times the average consumption per customer.

Table 47. Illustrative load research data for marginal cost of service study

	Units	Residential	Secondary commercial	Primary industrial
Customer connection	# of customers	100,000	10,000	1,000
Secondary distribution	kWs	300,000	320,000	N/A
Primary distribution	kWs	303,000	325,000	250,000
Transmission	kWs	305,000	325,000	255,000
Generation capacity	kWs	307,000	330,000	258,000
Energy by time period				
On-peak	kWhs	245,600,000	396,000,000	206,400,000
Midpeak	kWhs	614,000,000	825,000,000	825,000,000
Off-peak	kWhs	614,000,000	252,600,000	442,200,000
All periods	kWhs	1,473,600,000	1,473,600,000	1,473,600,000
Class load factor		55%	51%	65%

Table 48. Illustrative marginal cost revenue requirement

	Residential	Secondary commercial	Primary industrial	Total
Customer connection	$8,000,000	$800,000	$80,000	$8,880,000
Secondary distribution	$12,000,000	$12,800,000	N/A	$24,800,000
Primary distribution	$24,240,000	$26,000,000	$20,000,000	$70,240,000
Transmission	$15,250,000	$16,250,000	$12,750,000	$44,250,000
Generation capacity	$30,700,000	$33,000,000	$25,800,000	$89,500,000
Energy by time period				
On-peak	$24,560,000	$39,600,000	$20,640,000	$84,800,000
Midpeak	$42,980,000	$57,750,000	$57,750,000	$158,480,000
Off-peak	$30,700,000	$12,630,000	$22,110,000	$65,440,000
Total	$188,430,000	$198,830,000	$159,130,000	$546,390,000
Average marginal cost per kWh	$0.128	$0.135	$0.108	$0.124

The primary industrial class has a less peak-oriented usage and 100 times the average consumption per customer of the residential class.

Table 48 combines the marginal costs by element with the load research data to compute a marginal cost revenue requirement for each class, as well as the combined total.

As shown in Table 48, the illustrative MCRR for all classes combined is $546,390,000. It would be pure happenstance if this equaled the embedded cost revenue requirement determined in the rate case. More likely, the revenue requirement will be significantly more or less. The next step in a marginal cost of service study is reconciliation between the MCRR results and the establishment of class-by-class responsibility for the embedded cost revenue requirement.

There are two commonly used methods to reconcile the class marginal cost responsibility, as determined by a marginal cost of service study, to the utility embedded cost revenue requirement determined in the rate proceeding. The first method is equal percentage of marginal cost, which itself has two variants. The second is the inverse elasticity rule derived from Ramsey pricing. The approaches are very different.

In the EPMC approach, the embedded cost revenue requirement is compared with the total of the class marginal cost revenue requirements, also known as the system MCRR. For example, we offer two possible situations in tables 49 and 50 — one where the marginal cost is less than the revenue requirement, the other where it is more — and show the result of adjusting the revenue for each class by a uniform percentage. The class marginal cost revenue requirements

Table 49. EPMC adjustment where revenue requirement less than marginal cost

	Residential	Secondary commercial	Primary industrial	Total
Marginal cost revenue requirement	$188,430,000	$198,830,000	$159,130,000	$546,390,000
Embedded cost revenue requirement				$500,000,000
Ratio of embedded cost to marginal cost				92%
Reconciled revenue requirement	$172,431,779	$181,948,791	$145,619,429	$500,000,000

Table 50. EPMC adjustment where revenue requirement more than marginal cost

	Residential	Secondary commercial	Primary industrial	Total
Marginal cost revenue requirement	$188,430,000	$198,830,000	$159,130,000	$546,390,000
Embedded cost revenue requirement				$600,000,000
Ratio of embedded cost to marginal cost				110%
Reconciled revenue requirement	$206,918,135	$218,338,549	$174,743,315	$600,000,000

are adjusted by the ratio of the embedded cost revenue requirement to the system MCRR, resulting in the amount of the embedded cost revenue requirement that each class is responsible for. In Table 49, the cost responsibility for each class is reduced 8% below the marginal cost of service.

It is important to note that the result of this allocation process is to determine a level of revenue that the regulator deems cost-reflective. The regulator often will apply other non-cost criteria to establish the level of revenue that each customer class will pay.

The EPMC is often functionalized, particularly in jurisdictions where power supply is a competitive non-utility service. Assume for purposes of the illustration in Table 50 that the total embedded cost revenue requirement of $600 million comprises $400 million of generation costs, $60 million of transmission costs and $140 million of distribution costs. Table 51 shows how to reconcile costs for each function separately, which are then used to calculate the overall responsibility of each class for the embedded cost revenue requirement.

The illustrative functionalized EPMC results in Table 51 are close to the total EPMC results but slightly higher for

Table 51. Illustrative functionalized equal percentage of marginal cost results

	Residential	Secondary commercial	Primary industrial	Total
Distribution				
Customer connection	$8,000,000	$800,000	$80,000	$8,880,000
Secondary distribution	$12,000,000	$12,800,000	N/A	$24,800,000
Primary distribution	$24,240,000	$26,000,000	$20,000,000	$70,240,000
Marginal cost revenue requirement	$44,240,000	$39,600,000	$20,080,000	$103,920,000
Embedded cost revenue requirement				$140,000,000
Reconciled distribution revenue requirement	$59,599,692	$53,348,730	$27,051,578	
Transmission				
Marginal cost revenue requirement	$15,250,000	$16,250,000	$12,750,000	$44,250,000
Embedded cost revenue requirement				$60,000,000
Reconciled transmission revenue requirement	$20,677,966	$22,033,898	$17,288,136	
Generation				
Capacity	$30,700,000	$33,000,000	$25,800,000	$89,500,000
Total energy	$98,240,000	$109,980,000	$100,500,000	$308,720,000
Marginal cost revenue requirement	$128,940,000	$142,980,000	$126,300,000	$398,220,000
Embedded cost revenue requirement				$400,000,000
Reconciled generation revenue requirement	$129,516,348	$143,619,105	$126,864,547	
Total reconciled revenue requirement	$209,794,006	$219,001,733	$171,204,261	$600,000,000

Table 52. Total EPMC results with lower marginal generation costs

	Residential	Secondary commercial	Primary industrial	Total
Marginal cost revenue requirement	$133,170,000	$137,240,000	$103,720,000	$374,130,000
Embedded cost revenue requirement				$600,000,000
Ratio of embedded cost to marginal cost				160%
Reconciled revenue requirement	$213,567,476.55	$220,094,619.52	$166,337,903.94	$600,000,000

residential and slightly lower for primary industrial customers.

However, if the marginal generation costs are considerably lower, functionalization can have a different impact. Assume that marginal energy costs are half of the estimates in Table 48 and marginal generation capacity costs are 80% of those in Table 48 (e.g., because of low gas prices, a shorter time horizon for cost estimation and excess capacity). These results are shown in tables 52 and 53.

As shown in Table 53, functionalization blunts the impact of lower marginal generation costs. Compared with Table 52, the residential class actually has a lower share of the embedded cost revenue requirement under functionalization with lower marginal generation costs. Table 54 on the next page compares the results for the residential class from tables 50, 51, 52 and 53.

Comparing the two functionalization scenarios, the residential share of embedded costs ends up very slightly higher in the lower marginal generation scenario, but the difference is less than 1%.

The second general approach used for marginal cost of service study application is the inverse elasticity rule.

Table 53. Functionalized EPMC example with lower marginal generation costs

	Residential	Secondary commercial	Primary industrial	Total
Distribution				
Customer connection	$8,000,000	$800,000	$80,000	$8,880,000
Secondary distribution	$12,000,000	$12,800,000	N/A	$24,800,000
Primary distribution	$24,240,000	$26,000,000	$20,000,000	$70,240,000
Marginal cost revenue requirement	$44,240,000	$39,600,000	$20,080,000	$103,920,000
Embedded cost revenue requirement				$140,000,000
Reconciled distribution revenue requirement	$59,599,692	$53,348,730	$27,051,578	
Transmission				
Marginal cost revenue requirement	$15,250,000	$16,250,000	$12,750,000	$44,250,000
Embedded cost revenue requirement				$60,000,000
Reconciled transmission revenue requirement	$20,677,966	$22,033,898	$17,288,136	
Generation				
Capacity	$24,560,000	$26,400,000	$20,640,000	$71,600,000
Total energy	$49,120,000	$54,990,000	$50,250,000	$154,360,000
Marginal cost revenue requirement	$73,680,000	$81,390,000	$70,890,000	$225,960,000
Embedded cost revenue requirement				$400,000,000
Reconciled generation revenue requirement	$130,430,165	$144,078,598	$125,491,237	$400,000,000
Total reconciled revenue requirement	$210,707,823	$219,461,226	$169,830,951	$600,000,000

Table 54. Residential embedded cost responsibility across four scenarios

	High generation marginal costs	Low generation marginal costs
Total EPMC results	$206,918,135	$213,567,477
Functionalized EPMC results	$209,794,006	$210,707,823

As discussed in Chapter 24, it is based on Ramsey pricing, an economic theory that efficiency is enhanced when the elements of the rate that are "elastic" with respect to price are set equal to some measure of marginal cost, and that adjustments to reconcile the revenue requirement should be applied to the least elastic component or components in order to maximize economic efficiency. This approach was popular during the era when marginal costs were significantly higher than average costs reflected in the revenue requirement.[242] For that reason, we show the application of the inverse elasticity rule only for a situation where the revenue requirement is lower than system marginal costs.

The least elastic element of utility service is often deemed to be the connection to the grid: the customer-related component of costs such as billing and collection, and the secondary service lines to individual structures. Evidence suggests this to be true historically. Whether utilities assess a monthly customer charge of $5 or $35, nearly all residences and businesses subscribe to electric service, although customer charges likely influence decisions whether to master-meter multifamily buildings, accessory dwelling units and offices. Economists generally agree that price more significantly influences actual customer usage of kWs and kWhs.

This may become significantly different where customers have more feasible choices to disconnect from the grid or obtain some services from on-site generation and storage. For example, pedestrian crossing signals often are now being installed with solar panels and batteries, without any connection to the grid. This phenomenon potentially could extend to larger users, depending on the levels of monthly customer charges, usage-related charges, and solar and storage costs.

Table 55 shows a marginal cost reconciliation of the same costs in Table 49 but by first reducing the customer and secondary costs by class and then applying an EPMC adjustment to the residual class marginal costs until the revenue requirement is reached.

In this illustrative example, the residential class benefits substantially and the secondary commercial class benefits somewhat compared with the straightforward application of the EPMC method in Table 49. As a result, the primary industrial class ends up paying a larger share of the overall embedded cost revenue requirement.

Table 55. Use of inverse elasticity rule

	Residential	Secondary commercial	Primary industrial	Total
Marginal cost revenue requirement	$188,430,000	$198,830,000	$159,130,000	$546,390,000
Customer connection costs	$8,000,000	$800,000	$80,000	
Secondary distribution costs	$12,000,000	$12,800,000	N/A	
Adjusted marginal cost revenue requirement	$168,430,000	$185,230,000	$159,050,000	$512,710,000
Embedded cost revenue requirement				$500,000,000
Ratio of embedded cost to adjusted marginal cost				98%
Reconciled revenue requirement	$164,254,647	$180,638,178	$155,107,176	$500,000,000

242 Until the early 1980s, for example, Oregon excluded customer and joint costs from the marginal cost reconciliation process on the theory that these were highly inelastic components of customer demand — to simply be connected to the system. When overall rates rose and later costs declined, Oregon moved to an EPMC approach (Jenks, 1994, p. 12).