

About this Newsletter

With significant changes taking place in the electric industry, customers, regulators, and utilities need to better understand marginal costs. In this issue of **Energy** we examine the issues associated with estimating and applying marginal costs, and the expanding and changing role of marginal cost studies.

Always fundamental to the assessment and design of innovative rates and energy efficiency programs, these studies are now also used to determine the costs and benefits of integrating renewable resources, customer-side generation, and innovative technologies.

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Marginal Cost Analysis in Evolving Power Markets: The Foundation of Innovative Pricing, Energy Efficiency Programs, and Net Metering Rates

By Metin Celebi and Philip Q Hanser

Introduction

The utility industry is undergoing its greatest transformation since Samuel Insull began creating an integrated electricity infrastructure throughout the United States in the early 1900s. The rapid changes taking place within the industry are a result of:

- ◆ *The emergence of regional transmission organizations (RTOs) to operate and maintain multi-state transmission systems*
- ◆ *The potential impact of greenhouse gas legislation and other environmental regulations*
- ◆ *The unbundling of the integrated utility*
- ◆ *The growing impact of renewable generation and energy efficiency*
- ◆ *The development of the smart grid*
- ◆ *The emerging wave of electric vehicles*

In this evolving environment, new information is needed to guide the decisions that utilities make. These decisions could include the cost-effective level of demand-side management, the value of a particular renewable resource, the cost-effectiveness of various rate designs, or the design of net metering rates for distributed generation.

The key to thinking about how to evaluate these various options is to keep in mind that they affect the utility's services, and therefore require an analysis geared toward the incremental evaluation of the impacts on the utility. The historical accounting cost analyses that are the basis for rates cannot provide the required information, but marginal cost analyses can do so.

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Marginal costs, as opposed to embedded historical or accounting costs, measure the additional costs of providing the next unit of service, whether that is the next unit of energy or the additional burden that adding a kilowatt of demand places on the electrical system, at a specific location, time, and quality. Understanding the true marginal costs of service can also reveal locations and times when the existing average embedded cost-based rates diverge significantly from marginal costs.

For example, historical embedded and marginal costs for distribution capacity in urban areas could differ substantially from non-urban areas. This could be due to the increase in the costs of equipment and right-of-way acquisition since the distribution system's initial installation, or because of differences in geographic characteristics across regions. These differences can induce significant cost-shifting between customers under the current rates once additional supply and demand resources are installed on customer sites.

At high penetration levels, electric vehicles could overload distribution system equipment¹ and require costly upgrades. Even before the distribution system is overloaded by electric vehicle charging, the timing of additional load could be problematic, for example, by charging at the height of a utility's load requirements. If rates do not correctly reflect the marginal costs of energy and capacity, then consumers will not have an incentive to avoid charging vehicles at such times.

Net metering is another example where cost-shifting could result from rates that do not reflect marginal costs. Net metered customers with distributed generation can yield an under-recovery of distribution and transmission capacity costs by the utilities. In particular, if a retail customer is currently paying for distribution costs in volumetric rates only, then the introduction of net metering for distributed generation could lead to those customers bypassing all or most of the distribution capacity costs by having a zero net load over the course of a month. This would be the case even though they are strongly relying on the distribution and transmission grid of the utility.

Marginal costs can also be applied directly or indirectly when setting rates, both for retail rates generally and also dynamic

rates such as critical peak pricing or peak time rebates. There are, however, several tasks that must be accomplished with great care in order to use marginal costs and capture their benefits without creating new problems.

First, the time frame over which marginal costs are calculated must be chosen appropriately for the application. Marginal costs can be calculated both as short-run and long-run, but their calculations require substantially different approaches and data.

Second, rates based on marginal costs need to be reconciled with revenue requirements. If forward-looking marginal costs exceed historical embedded costs, as is often the case, then a direct translation of marginal costs to rates will over-collect the required revenues. Marginal cost-based rates will need to be adjusted in order to prevent this. Care must be taken to avoid dulling the behavioral incentives that marginal costs are meant to provide in the reconciliation process.

Third, in designing marginal cost-based rates, customer responses to those rates must be appropriately accounted for. Failing to do so may result in unintended revenue deficiencies or changes in load patterns that increase costs.

With the significant changes in the structure and institutions of the electric industry, not only have the various uses of marginal costs changed but so have the calculations. The increasing reliance of utilities on RTOs and markets to provide transmission services, ancillary services, and generation capacity yields significant differences in the approach to calculating marginal costs.

Moreover, many regulatory policies, such as renewable generation initiatives, new environmental regulations, and increasing reliance on demand resources, require the consideration of risk in calculating marginal costs through their impact on future electricity generation costs and capacity market supply-demand balance. Customers and regulators, not just utilities, must better understand marginal costs, regardless of their many potential applications. This newsletter examines several issues associated with marginal cost studies.

Estimating Marginal Costs

Traditional utility ratemaking is founded upon fully allocated (or embedded) cost of service (FACOS) studies. The goal of such studies, as the name implies, is to calculate the cost component of a utility’s revenue requirement. An embedded cost of service study first *functionalizes* costs according to whether they are production, transmission, distribution, customer, or general in nature. It then *classifies* those costs as to whether they are demand- (kW), energy- (kWh), or customer-related. Finally, a cost of service study *allocates* those costs to rate classes.

Note that all of these procedures are essentially administrative, and although they are guided by the principle of cost causation, their factual basis is historical accounting information. Thus, the unit of time used in such studies is usually no shorter than a year, nor is there often detailed granularity in the costs that are incurred by a utility in order to provide its services.

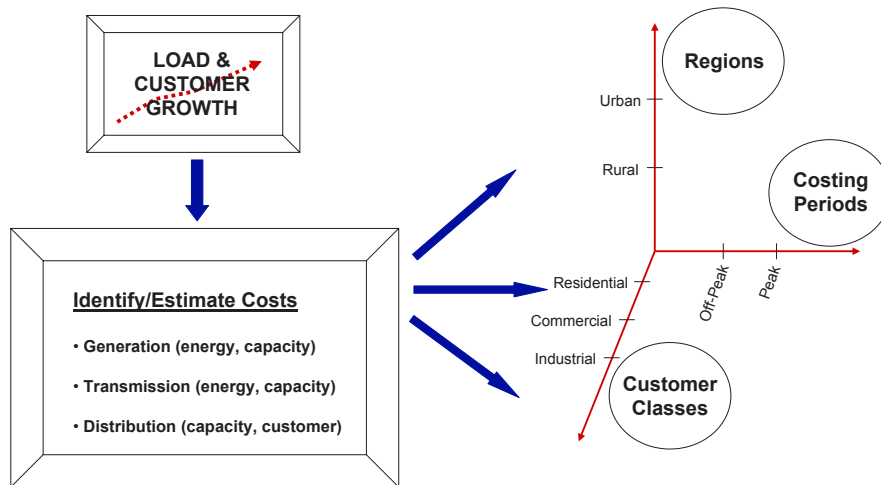
A marginal cost study, on the other hand, aims to answer how much it will cost the utility to provide an additional unit of service. Key questions include: what is incremental? What additional resources will need to be brought to bear in providing these services? A marginal cost analysis will assess the incremental costs of an additional kilowatt of demand or

a kilowatt-hour of energy, or to serve an additional customer at a particular time and place. The incremental costs may result from additional fuel use, transmission congestion, or additional ancillary services.

Such incremental services may also trigger the need for new generation capacity or expansion/enhancement of transmission and/or distribution facilities which may, in turn, increase the utility’s risk management requirements. In FACOS studies the implicit assumption is that all resources are utilized, whereas in marginal cost analyses specific resources to provide a specific service are brought to bear.

Estimation of marginal costs also involves functionalizing among generation, transmission, and distribution costs. However, the functionalization is done for different time frames and specific locations. They are classified (as demand-, energy-, and customer-related) but only for the incremental costs at the aggregate company level. These costs are then assigned to time periods (such as summer peak, winter off-peak, etc.), regions, and customer classes (by voltage level such as primary, secondary, and transmission level connections) in order to quantify the incremental cost of serving load across these dimensions.

Figure 1 - Marginal Cost Methodology



The estimation of marginal costs involves a detailed analysis of projected costs of various services provided by utility companies, and it is typically quite sensitive to certain parameters and assumptions depending on the type of cost being estimated. These key assumptions and study choices are as follows.

♦ **For capacity-related costs** such as investment expenditures for new generation or the cost of providing additional transmission capacity: the time period used to estimate projected or historical marginal capital investments is key. Is the time horizon a year, five years, or the length of the utility's planning horizon? What capital investments can be made utilizing the time span decided upon?²

Having decided the time period over which the capital costs are incurred, it is important to account for the lumpy nature of capital expenditures that are made to meet load growth. Even though load may grow gradually each year, capital expenditures to build large transmission or generation projects are typically done less frequently. Therefore, the duration of the time period over which capital will be expended to meet incremental load growth should include an assessment of the implications of such lumpiness.

♦ **For energy-related costs** such as congestion cost components of transmission-related or generation energy costs: the major determinants are fuel prices, variable emission costs (SO₂ and NO_x, and CO₂ in the future), and the projected congestion constraints (or if it is an RTO region, the locational marginal prices or LMPs). The projection of congestion constraints and the resulting congestion costs should be consistent with the assumed generation and transmission capital investments in the estimation of marginal capital costs.

♦ **For customer-related costs** such as meters and service drops: care must be taken to properly account for the differences across customer classes both in terms of equipment requirements and service costs. In addition, some types of service may come with additional burdens on areas of the company that interface with the customer, such as the customer service department.

The analysis of marginal capacity costs is broken down into separate analyses of generation, transmission, and distribution capacity costs. Marginal energy costs are the next category

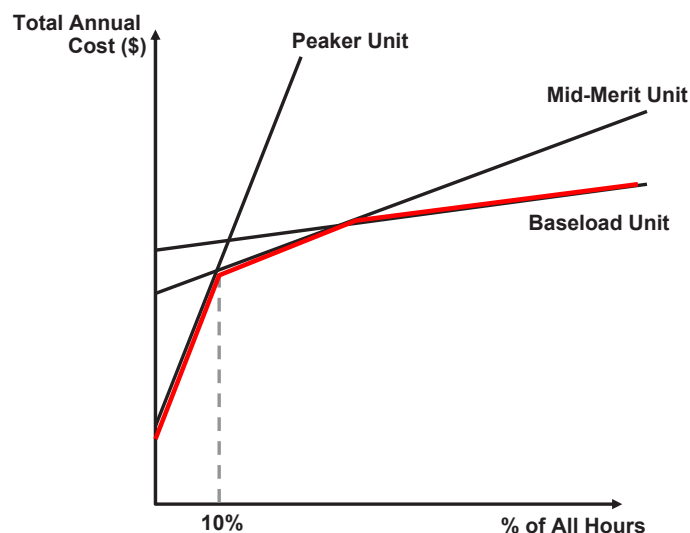
of costs to assess, followed by marginal customer costs. The following sections describe how these analyses are performed.

1. Marginal Generation Capacity Costs

Meeting an additional unit of demand will have an impact on generation requirements as well as transmission and distribution systems. Traditionally, the "upper bound" for generation capacity costs in the long-run equilibrium has been taken to be that of a combustion turbine, although in some markets a combined cycle gas turbine, net of fuel savings, may be a lower cost alternative and therefore more appropriate. The rationale for this ceiling on costs is that it represents the least cost response by a utility to an increase in demand while maintaining the same level of reliability.³

As illustrated in Figure 2, a peaker (combustion turbine) is typically the lowest cost generation option to provide capacity benefits during the top demand hours, while mid-merit and baseload plants become more economic to meet energy needs over longer time periods.

Figure 2 - Long-Run Marginal Cost of Generation



In restructured markets, however, prices in capacity markets have at times exceeded that of a combustion turbine. The reason is that the demand for capacity has exceeded supply. At such times, the marginal capacity cost component of rates should reflect such a premium.

This is more difficult to discern in RTOs without capacity markets such as the Midwest Independent System Operator (MISO) or the Electric Reliability Council of Texas (ERCOT), where only at equilibrium (that is at the long-run equation of supply and demand) does the market price settle to that of a combustion turbine. This market situation is symmetric; when supply has exceeded demand, the price in these capacity markets has been below that of a combustion turbine.

There are new situations in restructured markets that must also be considered in the calculation of marginal capacity costs, namely demand response and renewable resources. To the extent that customers are willing to experience lower levels of reliability and can be compensated at a cost below that of a combustion turbine, then that option must be considered.

Using demand response as the basis for marginal capacity costs, however, requires modification of those costs to include risk considerations. A combustion turbine has availability all year, while the availability of demand response varies across the year. Similarly, renewable resources may need to be considered in the computation of marginal capacity costs, but again, their costs must be suitably modified for the risk of their nonavailability.

2. Marginal Transmission Capacity Costs

The typical approach to estimating marginal transmission capacity costs involves first identifying what new transmission expenditures are required or planned to meet load and customer growth over a chosen time period. Next, such costs must be unitized by dividing them by the expected load and customer growth. It is critical to ensure that the length of this period is long enough so that the lumpy nature of transmission investments does not bias the results.

For example, if a utility plans to accelerate transmission investments over the next year to compensate for a lack of investment over some historical period, the study should cover investments over a period longer than one year to smooth out the effects of such abnormal years. Marginal cost estimates based on company data should be supplemented by engineering studies (when available) that identify in greater detail which type of transmission facilities in what capacities are needed to support load growth in a particular region.

Calculating the marginal transmission capacity costs has several components besides the incremental cost of new transmission capacity, and must also include the supporting transmission services that an RTO would provide, such as integration costs for renewables. Arguably, prior marginal costs studies may have been deficient because they failed to include such services. This may still be an issue for some current studies on fully integrated utilities.

The capability to deliver an incremental watt to a customer also requires the capability to generate a fraction of an incremental VAR (volt-ampere reactive) or reactive power, the generation capability to provide a means to respond to fluctuations in the frequency of power, as well as the ability to start up quickly in case of transmission or generation outages. These reliability-related services are the responsibility of the RTO and are integral to its role as operator of the transmission system. They are equally integral to the calculation of marginal transmission capacity costs.

The calculation of marginal costs for additional transmission capacity differs for utilities in RTOs. The rules for apportioning new transmission costs among its members differ in proportions and rationing principles across utilities, and are still in flux. For instance, the voltage level of transmission included for apportioning in the RTOs differs among the utilities. A utility may reinforce portions of its transmission system within its footprint, and those investments may not be fully included in the RTO's tariff. Thus, a utility in an RTO will need to blend its own estimate of the forward costs of new transmission capacity along with its RTO tariff in order to develop its marginal transmission capacity costs.

A potential pitfall in identifying the transmission costs for estimation is that these investments may be made for reasons other than meeting rising load. Transmission could be built to improve the interconnection with one or more neighboring utilities for system reinforcement or to facilitate wholesale power trading. Therefore, some care must be taken to ensure that the costs used for estimating marginal transmission costs are solely related to system load growth or reliability. Other types of transmission expansion costs should be reflected elsewhere in marginal cost-based rates (some marginal transmission costs, such as losses, are energy charges).

3. Marginal Distribution Capacity Costs

Marginal distribution capacity costs have a much different flavor now than in prior marginal cost studies. Cost differences across regions within a utility's footprint can be substantial. It is not unusual for a utility to have both older cities, where additions to the distribution system can be quite expensive, and suburban and rural areas, where distribution increments may be relatively less expensive.

Correctly calculating the difference in the level of these costs has significant impacts on the evaluation of smart grid benefits and demand-side management programs, which may have distinctly area-specific characteristics. This is the case particularly if they are aimed at mitigating local distribution system reliability problems. Similarly, estimates of marginal distribution capacity costs with sufficient locational granularity enables utilities to assess the investments and associated costs of upgrading distribution assets to accommodate additional load from electric vehicles, for instance.

A distinction must be made between customer-related and demand-related distribution costs in order to assess whether changes in the number of customers or changes in the load of existing customers would be the major driver of changes in distribution capacity costs. These costs can be distinguished either through an econometric analysis such as the "zero-intercept" method⁴, or through engineering estimates that identify the minimum distribution equipment necessary to connect a customer to the grid.

4. Marginal Energy Costs

Marginal energy costs have historically been based on the so-called "system lambda." System lambda is the cost of the next kilowatt-hour that can be produced by an electrical supply system's generating units. By now, participants in RTOs are all too familiar with the impact that congestion can have on LMPs. Such variations in costs must be accounted for on an area-specific basis, just like marginal distribution capacity costs, but also on their variation over the course of the year and in future years.

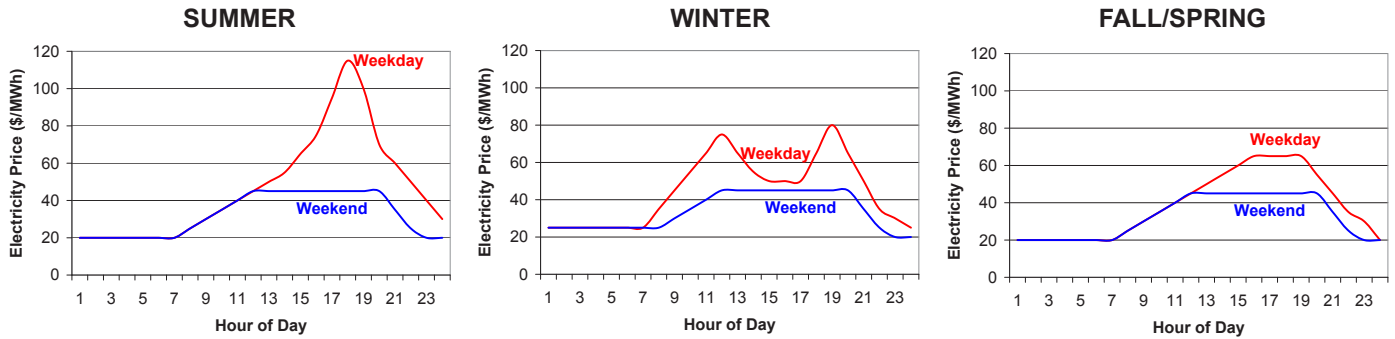
The marginal cost of producing and delivering electricity can and does vary significantly at different times. Indeed, the marginal cost of producing electricity often varies sharply over the course of a single day, particularly during peak periods. Therefore, a necessary step in the completion of a comprehensive marginal cost study is the identification of appropriate seasonal and diurnal costing periods that recognize systemic differences in a utility's load characteristics and variable costs of producing electricity.

Since the estimated marginal energy costs are hourly, but the costing periods are much broader, these costs must be aggregated. Aggregation methods include simple averaging across all of the hours within a rating period, selection of "typical" hours within the rating period (i.e., the mode or median), and weighted averages by a reliability measure such as loss of load probability (LOLP).

Figure 3 illustrates how the costing periods could be determined based on the time profile of hourly prices of electricity in the development of, for example, a time-of-use retail rate. In the illustration, a utility with a summer peaking price profile is shown. The weekday average hourly prices during summer are the highest during hours 14 to 19, while winter prices show a double-peaking pattern in the morning and late afternoon. This information can be used to group hours into costing periods in such a way that the marginal costs are similar during hours within each period, but significantly different across periods. The bottom half of the illustration shows how costing periods based on seasons and peak/shoulder/off-peak hours can be summarized.

Once costing periods have been chosen, costs need to be assigned to the selected periods. Capacity costs are typically allocated on a reliability criteria basis. LOLP, loss of load energy, and reserve margins have all been used. However, since the study is concerned with the incremental effects of a change in load, the relevant reliability measure must account for the fact that incremental capacity provides improved reliability at all hours. Thus, marginal capacity costs should be attributed to periods based on their relative outage or shortage costs. Energy costs must also be allocated to a rating period.

Figure 3 - Determination of Costing Periods



WEEKDAY COSTING PERIODS																									
Season	Month	Hour Beginning																							
		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Summer	June																								
Summer	July																								
Summer	August																								
Summer	September																								
Fall/Spring	October																								
Fall/Spring	November																								
Winter	December																								
Winter	January																								
Winter	February																								
Fall/Spring	March																								
Fall/Spring	April																								
Fall/Spring	May																								

WEEKEND COSTING PERIODS																									
Season	Month	Hour Beginning																							
		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Summer	June																								
Summer	July																								
Summer	August																								
Summer	September																								
Fall/Spring	October																								
Fall/Spring	November																								
Winter	December																								
Winter	January																								
Winter	February																								
Fall/Spring	March																								
Fall/Spring	April																								
Fall/Spring	May																								

	Peak
	Shoulder
	Off-Peak

Applications of Marginal Costs

As mentioned previously, marginal cost estimates can be used to evaluate and design energy efficiency and demand response programs, as well as renewable resources. A proper marginal cost study provides information on a utility's avoided cost of energy and capacity due to reduced demand in different time periods and locations. To illustrate how marginal cost estimates can be used to evaluate the benefits of such programs, we present in Figure 4 a simplified example of a utility that serves customers in two regions and examine the benefit-cost analyses of energy efficiency programs.

The densely populated "Crowded City" is in a transmission-constrained load pocket, while "Dairy Town" is located in a more remote rural area that does not suffer from transmission congestion. In addition, the higher value of land and the regulations requiring use of underground distribution lines make the cost of new generation and distribution capacity higher in Crowded City. The illustrative marginal costs of energy, capacity, and customer costs during summer peak and other periods are also summarized.

Figure 4 - Illustrative Marginal Energy, Capacity, and Customer Unit Costs

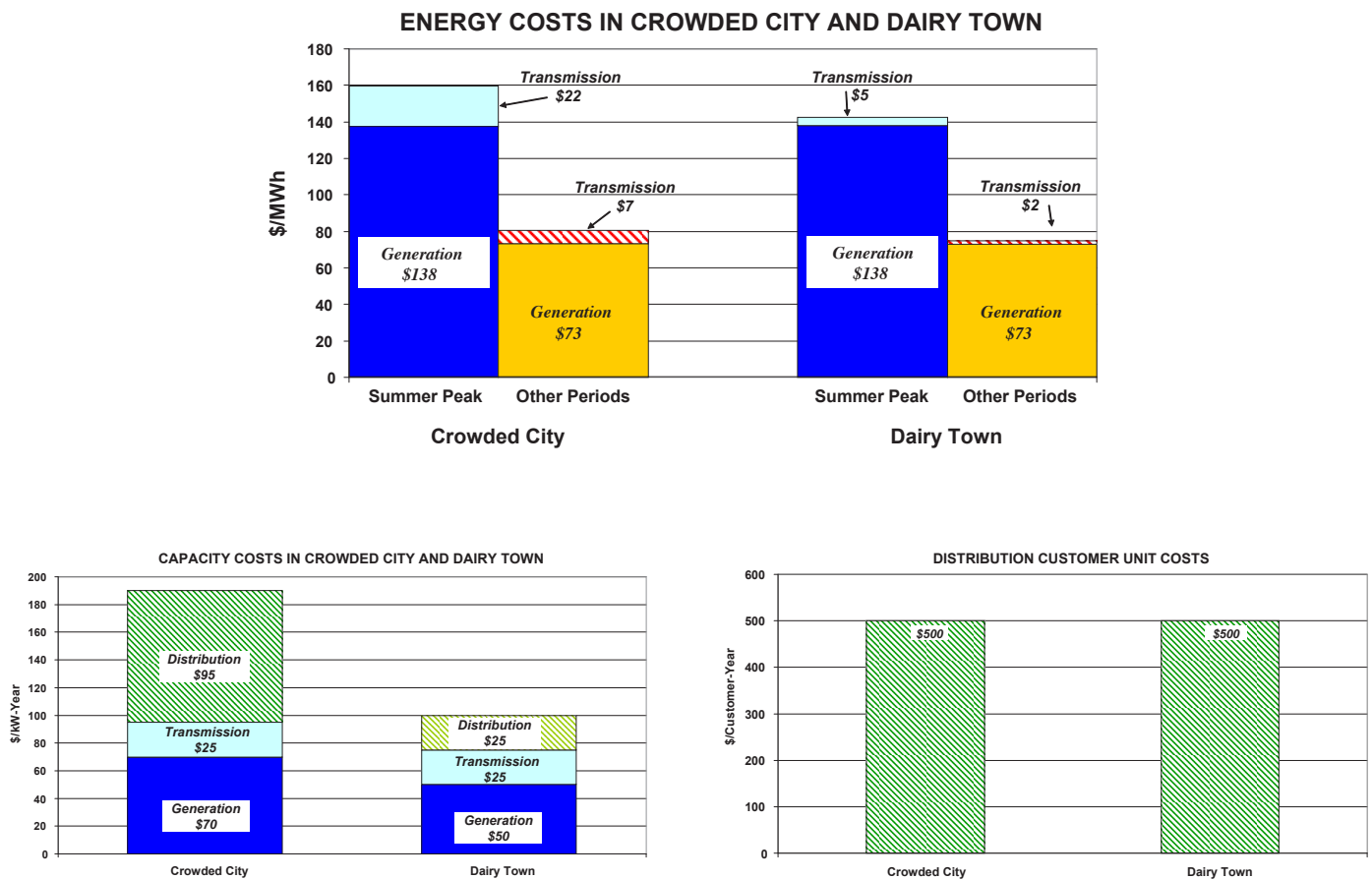


Figure 5 - Load Shape by Costing Period in Crowded City and Dairy Town

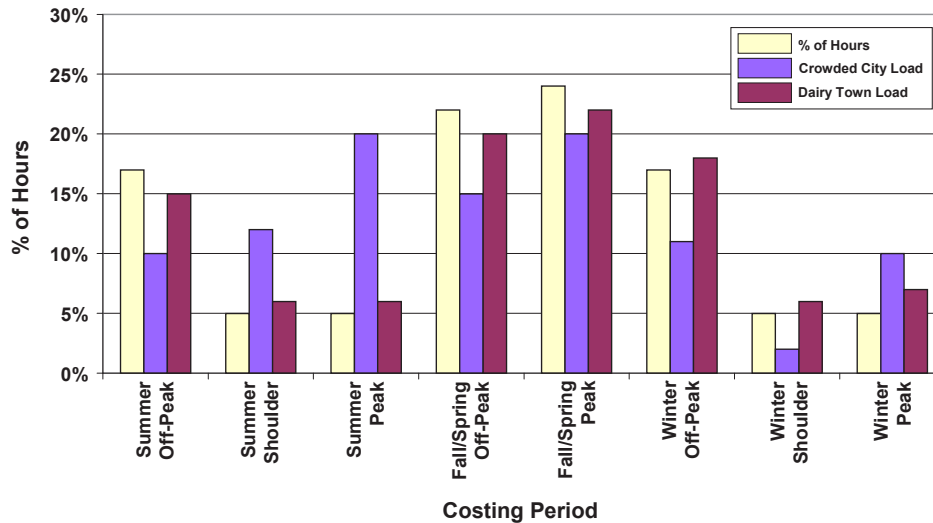
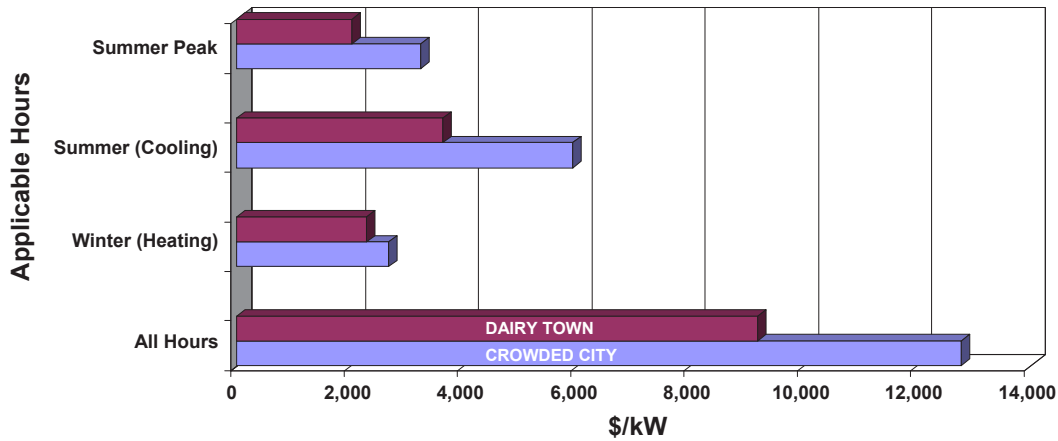


Figure 6 - Maximum Cost of Efficiency Programs Justified in Crowded City and Dairy Town



During summer peak hours, marginal energy costs (including generation and transmission) are about \$20/MWh higher in Crowded City than in Dairy Town (\$160/MWh vs. \$143/MWh). The capacity costs (generation, transmission, and distribution costs) in Crowded City are almost twice those of Dairy Town (\$190/kW-year vs. \$100/kW-year).

Although both regions have a summer-peaking load, the load shapes are significantly different: Crowded City has a lower load factor with much higher load during the peak hours, reflecting higher urban population density and higher penetration of air-conditioning and lighting equipment.

Figure 5 summarizes the share of annual load in various costing periods in two regions. In Crowded City, about 20 percent of the annual load takes place during the summer peak hours, even though summer peak represents 5 percent of the total hours. In Dairy Town, the period share of annual load is closer to the percentage of annual hours in each period, reflecting the flatter load shape in that region.

Given the illustrative marginal costs and load shapes summarized, the potential benefits of implementing utility-sponsored energy efficiency and demand response programs in the two regions can be determined. Instead of assuming

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specific costs to implement these programs, we show the maximum marginal costs that can be justified (i.e., that would not exceed the marginal benefits). We express these costs in total lifetime costs per kilowatt of reduction in load by assuming an eight percent fixed charge rate to convert the one-time costs to annualized revenue requirements.⁵

As shown in Figure 6, the higher marginal costs in Crowded City justify more expensive programs. For example, a program

costing up to \$13,000/kW that could be used to reduce load around the clock (all hours), such as subsidies for efficient appliances and building isolation materials, would be justified in Crowded City. Only such programs costing up to about \$9,000/kW in Dairy Town would be justified by the benefits. For other conservation programs that are applicable in fewer hours (such as programs to reduce cooling load during summer hours or heating load during winter hours), the program costs need to be much lower in order to be justified by the benefits.

CONCLUSION

Utilities must assess their needs for performing a marginal cost analysis, and the answers to questions such as these will guide the utility's decision:

- ◆ *How stale are the past analyses of marginal costs?*
- ◆ *Do new technologies installed by customers affect the utility's cost drivers?*
- ◆ *Are there trends in costs that are likely to produce significant differences between the incremental costs of serving load or customers that are not fully reflected in current rates?*
- ◆ *Are there new services being requested by customers whose incremental cost impacts are uncertain?*
- ◆ *Will the utility be instituting any new dynamic rates in the future?*
- ◆ *Are there new renewable resources that must be integrated into the utility's portfolio?*

The uses of marginal cost studies have broadened over time. Always fundamental to the assessment and design of innovative rates and energy efficiency programs, these studies are now also used to determine the costs and benefits of integrating customer-side generation, renewable resources, and innovative technologies such as smart meters and plug-in electric vehicles. In addition, the changed settings of some utilities have substantial impacts on how marginal costs are calculated. The drivers may be the same as before, but the cost consequences are not. ■

ENDNOTES

¹ Schneider, K., C. Gerkenmeyer, M. Kintner-Meyer, and R. Fletcher, "Impact Assessment of Plug-in Hybrid Vehicles on Pacific Northwest Distribution Systems," conference paper presented at IEEE Power and Energy Society General Meeting - Conversion and Delivery of Electrical Energy in the 21st Century, 2008. Available at: <http://www.pnl.gov/publications/abstracts.asp?report=232441>.

² A fixed charge rate will need to be calculated to annualize the capital expenditures of long-lived assets. The estimated fixed charge rate, in turn, is a function of several variables, including financing assumptions (debt/equity ratio, cost recovery period, cost of capital, etc.), assumed rate of inflation for materials and other construction costs, and construction period.

³ Any other generation option would have higher capital costs but lower fuel costs. Therefore its value to the utility would not be solely that of providing an additional kilowatt of capacity.

⁴ The zero-intercept method used to estimate customer-related costs involves performing a regression analysis to explain the variations in distribution capital costs over time by changes in peak distribution load, and attributing the estimate for the constant term in that regression to customer-related costs.

⁵ The assumed 8 percent fixed charge rate reflects a utility with a 7.2 percent after-tax weighted average cost of capital (ATWACC), capital investments with economic life of 30 years, and an inflation rate of 2 percent.

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We also have experience in designing and evaluating innovative pricing to reduce peak loads, demand response to prevent blackouts, energy efficiency programs to lower customer bills, renewable resources to protect the environment, and other customer-side smart grid applications.

The Brattle Group has assisted utilities in reviewing the accuracy and usefulness of their load forecasting tools and assessed the accuracy of their weather normalization methods. Such assessments have also been used for improving revenue forecasts and in formulating integrated resource plans.

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