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Pricing Do's and Don'ts:

Designing Retail Rates As if Efficiency Counts

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April 2011

Pricing Do's and Don'ts

Efficient Price Signals: Base Prices on Long-Run Marginal Costs

DO set prices for usage to reflect all relevant long-run costs, including production, transmission, distribution, administrative, customer service, and environmental costs.

DO set the basic charge at a level that includes only the utility's costs that vary by the number of customers.

DO consider inclining block rates for residential consumers to recognize higher resource costs in the future and typically greater use of power during peak periods by high-use consumers.

DO let customers choose a pricing option that varies according to time of day or market and system conditions.

DO make it easy for consumers who choose time-varying rates to shift energy use from peak load hours.

DO display the rate structure on the consumer's bill in a way that conveys the cost (savings) from increased (decreased) usage.

DO complement economically efficient pricing with energy efficiency programs that focus on reducing peak demand.

Align Society's Interests: Consumers, Utilities, and Third Parties

DO consider revenue decoupling to eliminate the incentive for utilities to increase sales in order to increase profits.

Some Pricing Options That Don't Always Solve Problems

DON'T raise the fixed customer charge to address the utility throughput incentive.

DON'T price kilowatt-hours cheaper by the dozen.

DON'T force consumers onto complex rate designs that they cannot understand or respond to.

DON'T shift risks with automatic adjustment mechanisms without considering the impact on consumers and adjusting the utility's allowed rate of return.

DON'T set the rate of return higher than the utility's incremental cost of capital.

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Pricing Do's and Don'ts:
Designing Retail Rates As If Efficiency Counts

The pricing of utility services is one of the most fundamental and far-reaching actions that utility regulators take. As is true of any other commodity, energy can be priced in various ways to induce various types of consumer – and producer – behavior. While the fundamental function of pricing is to provide the utility a reasonable opportunity to recover its allowed revenue requirement, part of this job is to ensure that retail rates help lead to the most economically efficient outcomes. Pricing cannot do everything – there are fundamental non-price barriers to efficiency. But a significant function of pricing is to provide utilities and consumers with appropriate incentives to minimize the long-run costs of service and to optimize usage (given desired levels of reliability).

This policy paper describes retail electricity pricing that fosters economic efficiency and improved consumer welfare through better use of existing power plants and delivery systems (operating plants when justified by cost-sensitive retail loads and improving utilization of generation and delivery assets), increased investment in cost-effective end-use energy efficiency,[1] peak demand reduction, and environmental protection. It also describes approaches to pricing that are not aligned with these goals. Retail pricing should complement wholesale market prices and prices that signal efficient investment in new generation. There are a variety of approaches to pricing and rate-making that we identify here – volumetric rates, declining-block rates, inclining-block rates, time-varying pricing, straight fixed-variable tariffs, and establishing an appropriate monthly customer charge – and the "do's" and "don'ts" associated with them. Because these pricing issues tie closely to utility sales growth incentives, we also address revenue decoupling.

Pricing as if Marginal Cost Matters

The standard electricity tariff for residential customers consists mainly of a fixed minimum monthly charge and a volumetric energy charge in kilowatt-hours (kWh) that covers both production and delivery costs.[2] The energy charge may be flat for all units used, it may increase or decline at higher usage levels, or it may be time-differentiated. For large nonresidential customers, some revenue requirements are separated from the energy rate and recouped through demand (kilowatt) charges.

Efficient Price Signals: Base Prices on Long-Run Marginal Costs

Electricity is unlike other commodities in many ways. First, it is essential to modern life. Second, there are few good substitutes for some key end uses. Third, it is highly capital-intensive to produce and distribute. Fourth, there are economies of scale and scope, so it may be inefficient to have multiple providers, at least for certain aspects such as delivery and reliability services. Fifth, depending on the generation mix, environmental effects may vary with patterns of customer demand.

In the long run, all utility costs are driven by expected sales volumes. Without an expectation of significant sales, utility grids and natural gas lines may not be extended into remote areas. It is simply cheaper to use substitutes for grid energy, including local generators, propane, and other fuels. Put another way, in the long run almost all utility costs, including power plants, transmission lines, and distribution facilities, are variable or "marginal," with respect to loads. Between investment cycles the costs may be fixed regardless of usage levels, but that has nothing to do with the factors that caused the investments to be made.

Economic theory holds that markets are in "equilibrium" when short-run marginal costs and prices are equal to long-run marginal costs. This occurs when existing facilities are used to nearly the limit of their capacity, and getting "more" out of them requires inefficient operation, making it profitable for producers to add new capacity.

Because of the need to ensure reliable electricity service, however, regulators require utilities to build excess capacity, so utilities don't exceed capacity under extreme conditions or when something breaks. Competitive firms do not face this reliability mandate: it is okay for a grocery store to run out of asparagus, because people can eat broccoli instead – and if they saw asparagus priced at $200/lb, they would choose to buy something else anyway. Once the utility system is built to a high standard of reliability, the system seldom operates at the cost and production levels (corresponding to high wholesale price levels) that would justify the addition of new capacity based solely on the marginal running costs of existing facilities. As a result, the regulator must substitute for the market to ensure that prices are set as they would be under competition[3] – at the point where short-run marginal costs and long-run marginal costs are equal.

DO set prices for usage to reflect all relevant long-run costs, including production, transmission, distribution, administrative, customer service, and environmental costs.

The utility's revenue requirement includes recovery of costs that are fixed in the short run, like depreciation and interest, plus variable costs like labor, taxes, and, for investor-owned utilities, a return on the shareholders' investment. The capital-related costs, however, are based on the "depreciated original cost" of the utility plant, not the current replacement cost. This is unlike other industries, which set prices based on what the market will bear, generally based on new product costs. As a result, the allowed revenue requirement established in the rate case may be lower than the cost to add new capacity to the system today. In short, long-run marginal cost is typically greater than average embedded or historic cost. Adding new plant is generally more expensive even relative to inflation, due to scarcity, and stricter land use and other environmental regulations.

By determining full replacement costs, and designing rates so that usage is priced at full incremental cost, consumers can make a rational trade-off between electricity consumption and available alternatives, including more efficient technology, alternative fuels, or other uses for their money.

The long-run marginal cost should include all production, transmission, distribution, customer service, administrative, and environmental compliance and safety costs, plus the costs of reserves and marginal line losses. This will typically be much higher than the short-run variable cost on the system for most hours of the year.

Normally, if all utility service were priced at this level, the utility's total revenue would exceed the allowed revenue requirement. The "consumer surplus" that is available should, under economic theory, be returned to consumers in the manner that least distorts efficient consumption (generally price-insensitive elements of service) – specifically, by reducing unavoidable charges, pricing infra-marginal usage at infra-marginal rates (for example, through inclining-block pricing – discussed further below – that may, in part, reflect the underlying characteristics of historic cost in lower usage blocks),[4] and pricing incremental usage at full incremental long-run cost.

DO set the basic charge at a level that includes only the utility's costs that vary by the number of customers.

The only costs for a utility that truly vary with the number of customers are metering, meter reading, billing, payment processing, and some customer service expenses. Basic service charges should ideally be limited to costs that vary only with customer numbers in order to ensure that the character of costs match the characteristics of the service delivered.[5] These service charges typically cost utilities about $4 to $7 per month.

Most competitive firms do not have the luxury of charging customers for the privilege of being a customer; they charge only for usage or purchase of their products.[6] While hotels, oil refineries, and supermarkets have significant costs that do not vary with usage, they must recover these through volumetric charges. Among the "competitors" to utilities are vendors of efficient windows and high-efficiency lighting and appliances. The vendors of these end use devices are in the same situation as other competitive businesses – they can only recover their costs through volumetric prices. Utilities can justify a customer charge that recovers the basic costs outlined above because they are directly related to the number of customers receiving an essential monopoly service.

DO consider inclining block rates for residential consumers to recognize higher resource costs in the future and typically greater use of power during peak periods by high-use consumers.

Inclining block rates charge a higher rate per kWh at higher levels of energy usage (and a lower rate at lower usage levels). Inclining block rates are cost-based for two reasons.

First, existing utility plant (power plants, transmission and distribution systems) are typically (but not always) cheaper than new units, simply due to inflation.

In instances where the forward-looking costs of all new resources are higher than some existing or "embedded" resources, the higher incremental unit price signal should, ideally, be communicated to all consumers. For some utilities, this can be as simple as setting a limited "initial" block for all customers, with a rate for power based on the cost of lower-cost, older units (e.g., hydroelectric) and a higher rate for newer thermal and renewable energy generation.[7] In theory, the next kWh consumed by both large and small customers affects the resource needs of the collective utility system. However, where the unit price signal is set high to reflect higher future costs than historic costs, setting all unit prices based on forward-looking costs in many cases would result in a profit windfall for the utility. Therefore, some portion of usage must be priced below long-run incremental cost. Concentrating the "discount" in the first block of usage will avoid disturbing the important relationship between incremental cost and the price for incremental usage.

Second, the end-uses associated with higher levels of residential usage – mostly space conditioning (heating and cooling) – coincide far more with peak demand hours on the utility system than basic usage like lights and appliances. The annual load factor[8] of space conditioning can be as low as 15 percent, compared with 70 percent and higher for basic usage. A lower load factor means higher capacity costs per kilowatt-hour, and therefore justifies higher prices for higher levels of usage. In other words, more of the fixed-costs must be spread over fewer unit charges creating a higher unit price. If a typical rate design for large non-residential customers, containing a separate demand and energy charge,

Demand-Cost Basis for Inverted Rates

Commercial Tariff:

Demand, per kW: $10.00
Energy, per kWh: $0.10

Residential Block Rate Based on Commercial Rate

End Use	Lights and Appliances	Water Heat	Space Conditioning
Rate Block	**First 500 kWh**	**Next 500 kWh**	**Over 1,000 kWh**
Load Factor	70%	40%	20%
Demand Cost/kWh	$0.020	$0.035	$0.069
Energy Cost/kWh	$0.100	$0.100	$0.100
Total Cost/kWh	**$0.120**	**$0.135**	**$0.169**

were applied to the different blocks of residential usage, an inclining block rate would result, as shown above.

DO let customers choose a pricing option that varies according to time of day or market and system conditions.

Advances in metering technology have lowered the costs and enhanced capabilities to measure consumption each hour and even shorter time frames. Time-varying pricing can help to communicate to retail customers the higher costs of energy demands during periods when the costs of energy, capacity, and system losses are greatest. It helps promote economically efficient behavior by allowing customers to decide whether they would prefer to pay the high costs of on-peak consumption or to reduce or defer consumption when the value of electricity to the customer is less than the capital and operating costs of additional electricity production and delivery.

While large industrial customers have sophisticated energy management staff and equipment, residential consumers typically do not. However, residential consumers can alter their behavior to use less power at peak periods.

Providing optional rate schedules that allow residential consumers who can shift energy use to pay lower bills will encourage those consumers to modify their usage patterns, typically including some reduction in energy use overall. These can include year-round, fixed-period time-of-use rates or dynamic pricing rates, where prices vary depending on market or system conditions. For example, "critical peak pricing" rates are much higher compared to standard rates during a small fraction of the year – the highest cost hours such as late afternoon during the hottest summer days – and lower than standard rates the rest of the year. Studies demonstrate that the impacts of dynamic pricing on peak vary significantly with the specific designs and the extent to which designs have been coupled with technologies permitting automated response.[9]

Another option is to use "peak time rebates" where customers receive a credit on their bill for reducing usage on request of the utility, presumably at time of peak demand. Peak time rebates are sometimes attractive because they offer a carrot without a stick; there are no direct consequences for consumers who do not reduce their usage during peak time events.[10] However, peak time rebates pose several problems:

- First, because the underlying rates typically are not time-differentiated, peak time rebates may not provide an incentive for consumers to shift on-peak loads long-term or to support solar and energy storage technologies (unless peak time rebates are combined with inclining block rates).[11]

- Peak time rebates also may not assist in any transition to dynamic pricing. In fact, they make it more difficult to educate consumers about dynamic pricing – where customers pay *more* for electricity use during on-peak hours (particularly critical-peak hours), instead of getting a rebate for cutting usage at those times. In addition, "baseline" usage must be calculated monthly for each participant in order to estimate the differential necessary to calculate the incentives.[12] Baseline calculations can be highly contentious, lack transparency, and add administrative costs (though smart grid infrastructure will minimize the cost).

- Further, peak time rebates provide customers with only a positive incentive for shifting loads. Studies to date suggest that consumers may reduce peak demand more in response to critical peak pricing than to peak time rebates.[13]

The environmental effect of load shifting varies by utility and by region. Shifting loads from on-peak to off-peak can mean that more power is produced by high-efficiency power plants that are underutilized at night, or may involve adverse environmental consequences if it means that less power is provided by natural gas generators and more is dispatched from coal plants. Even here, however, the environmental consequences of shifting loads can be expected to improve over time if renewable energy generation and efficient natural gas generation continues to replace the highest emitters – older and less efficient coal generators. Studies to date also suggest that dynamic rates lead to a modest reduction in energy consumption of 1 percent to 6 percent.[14, 15]

It is relatively easy to design rates that reflect both time-of-use elements and inclining-block elements. The most common is to simply calculate a time-of-use bill, and then apply a discount for the first few hundred kilowatt-hours. Following is a residential tariff example with a discount for the high load-factor essential uses of electricity for lights and appliances of about 400 kWh per month:

Rate Element	Purpose	Amount
Basic Charge	Basic metering and billing costs	$5.00/month
Off-Peak Usage	Recover costs of baseload generation, transmission, and distribution	$.08/kWh
On-Peak Usage	Recover additional costs of peaking generation plus incremental transmission and distribution	$.15/kWh
Inclining Block Discount	Reflect generally higher load-factor end-uses in initial block	$.04/kWh for up to 400 kWh/month

DO make it easy for consumers who choose time-varying rates to shift energy use from peak load hours.

The most complete experiments involving time-varying pricing for residential consumers showed that those who could automate their responses to high prices had the highest reductions in peak demand and the most economic benefits.[16] Programmable communicating thermostats can receive a high price signal from the utility and automatically reduce space heating or cooling during critical peak or on-peak hours. Controlling water heaters also can shave peak demand at times when it is most beneficial for the utility system -- during peak demand hours as well as during hours when there is surplus generation from wind and solar resources. Home energy management systems are likely to become more common in the future, providing for more complete load control.

DO display the rate structure on the consumer's bill in a way that conveys the cost (savings) from increased (decreased) usage.

Utility rates have become extremely complex, with fuel cost adders, other adjustment clauses, and state and local taxes. Unfortunately, many utility bills simply reflect this complexity instead of successfully explaining it. Consumers need to know exactly how much they will pay if they use more energy, and how much they will save if they use less. If timing of usage matters, the bill should clarify this also. The consumer bill should show the total price per kilowatt-hour of electricity or therm of natural gas in each rate block, *including* all adders, credits, taxes, and surcharges. Home energy reports and Internet tools offer opportunities to explain customer bills in new and better ways.

DO complement economically efficient pricing with energy efficiency programs that focus on reducing peak demand.

Economically efficient pricing, while very important, will not by itself remove all barriers to investment in cost-effective end-use energy efficiency. Consumers will still lack important information and tools to respond. Programmatic responses to these barriers are still needed.

Energy efficiency programs that focus on end-uses during peak periods reduce both energy and capacity costs, and therefore are more cost-effective than programs that do not target peak loads. When one utility fully considered the load-shape and distribution capacity cost benefits of residential weatherization, it was able to nearly double the cost-based incentive payment to low-income weatherization agencies that assist consumers.[17]

Understanding the load factors and load shapes associated with specific end-uses enhances the utility's ability to target efficiency programs to loads that coincide with peak demand on the utility system. This may require specific load research studies. As described above, the environmental impacts of load shifting varies by utility and region and will change as dirtier coal generation is replaced by cleaner generating facilities.

DO consider revenue decoupling to eliminate the incentive for utilities to increase sales in order to increase profits.

Conventional ratemaking fixes prices in a rate case, and lets utility revenue move up and down with sales volumes. Revenue decoupling is an alternative approach to utility regulation that fixes the allowed revenue (or revenue per customer), and then makes small adjustments to rates between rate cases to assure that the allowed revenue level is recovered regardless of sales volumes.

There are a number of benefits to decoupling. The most important are giving the utility assurance it will receive its allowed revenue to cover investment and labor costs supporting service and reliability that do not vary with usage, allowing the utility to focus on reducing costs to increase profits, and stabilizing consumer bills despite weather variations. In addition, under decoupling, utilities are less concerned with the effects of progressive rate design, including low customer charges and inclining rates, because these do not affect their actual revenue. Because decoupling does not affect rate design – it only involves very small adjustments applied across all rates -- regulators can use utility rate design to focus on the pricing objectives discussed elsewhere in this paper.

Decoupling adjustments (also called reconciliations) can be done on either a current basis (small adjustments in every billing cycle) or a deferred basis (adjustments once per year, with costs or credits deferred with interest). Either stabilizes utility earnings, but current decoupling has the added benefit of stabilizing consumer bills. For more information on decoupling, see www.raponline.org/docs/RAP_RevenueRegulationandDecoupling_2011_04.pdf

Align Society's Interests: Consumers, Utilities, and Third Parties

There are a number of tools that can be used to ensure that the best resource mix for consumers is also the most profitable for investors. Achieving this goal means that the utility will prefer to assist consumers with cost-effective energy efficiency or alternate fuel choices if that is best for the consumer.

Some Pricing Options That Don't Always Solve Problems

There are a number of utility pricing options that are often advocated by utilities and other experts that may appear to have a sound basis, but may be uneconomic and have proven ineffective in practice at achieving cost-effective energy solutions.

DON'T raise the fixed customer charge to address the utility throughput incentive.

Some utilities have sought to increase the basic charge for residential service to include transformer and distribution line costs, plus operating expenses such as distribution system maintenance. This approach is called "Straight Fixed Variable" rate design. The effect of this is to stabilize revenues when usage varies due to weather or customer conservation, which addresses utility concerns, but it also means that the usage-based price faced by consumers will typically be far below full long-run marginal cost, stimulating consumption that will cost everyone in the long run.

The decision to install a grid in the first place, and the sizing of wires and transformers (or pipes and valves), is essentially volume-driven with seasonal and time-of-day considerations. To the extent that regulation is a substitute for market forces, regulators should be careful in considering higher basic charges to recover costs that are incurred for utility infrastructure. In general, all distribution costs other than operating expenses, such as basic metering and billing, should be recovered through volumetric rates, reflecting the fact that utility distribution grids are justified only where usage levels are high enough to justify grid construction. In the long run, there are no fixed costs.

Many utilities are incurring additional costs for smart grid investments, including new sophisticated meters, meter data management systems, and new billing software. These additional costs are being incurred to reduce expenses beyond those for meter reading and billing, such as reducing outage management costs and the future cost of energy supply. Therefore any costs beyond those for basic metering should be recovered in usage rates, not in the fixed customer charge.

DON'T price kilowatt-hours cheaper by the dozen.

The cost of producing energy does not decline as usage increases. Long-run marginal costs are increasing, not decreasing, as utilities rely on lower-emission, higher-cost new resources. Higher consumption levels also introduce several distinct environmental costs. Declining block rates – where consumers pay *less* per kWh at *higher* levels of energy usage – send exactly the wrong price signal.

DON'T force consumers onto complex rate designs that they cannot understand or respond to.

Rates should be designed with consumer understanding in mind. Further, residential and small nonresidential customers should have the option, but not the requirement, of choosing time-varying pricing. This is particularly valuable in jurisdictions with significant seasonal variation in load that can be managed through appropriate pricing signals.

DON'T shift risks with automatic adjustment mechanisms without considering the impact on consumers and adjusting the utility's allowed rate of return.

An automatic fuel and purchased power adjustment clause that flows through all power costs without further adjustment has the effect of making all additional sales profitable, and makes profits decline when customers conserve electricity.[18] In addition, because automatic fuel and purchased power adjustment mechanisms reduce risks from exposure to fluctuating to prices to utility investors, the utility's allowed equity capitalization ratio and return on equity should reflect the change in risk.

Some adjustment mechanisms are designed to "track" certain costs that are rising without corresponding revenue gains. An example is a gas utility "infrastructure tracker" that recovers the cost of replacement of existing mains, where there is no increase in customer sales or revenue. These may be justified, but the regulator must be careful that this does not result in a situation where all *rising* costs are "tracked" while all *declining* costs, such as productivity gains, accrue to the utility until the next rate case. That can result in a "heads I win, tails you lose" situation for utilities.

DON'T set the rate of return higher than the utility's incremental cost of capital.

If the utility's allowed return on equity exceeds its incremental cost of capital, the utility has a powerful incentive to increase its rate base – the investment upon which it's allowed return is computed. This may cause an incentive to gold-plate or to grow sales, which does not necessarily benefit consumers. This may also create a strong incentive for grid modernization, which may be very beneficial in the long run. Ideally, the utility should be neutral to the addition of plant to its system – the return allowed should exactly equal the cost of debt and equity capital needed to finance the plant additions.[19]

One challenge in doing this relates to the cost of new debt relative to average interest on existing debt. The incremental cost of debt may be significantly different from the average cost of existing debt, which may further distort the incentive for optimal investment on behalf of consumers. The table below compares a hypothetical utility's marginal cost of capital to an average cost of capital, showing a situation where there is a powerful incentive to grow rate base.

In determining the cost of equity, it is useful to examine the analyses prepared by utility actuaries in planning their

	Allowed Cost of Capital				Marginal Cost of Capital		
	Ratio	Cost	Weighted Cost		Ratio	Cost	Weighted Cost
Debt	50%	7.0%	3.50%		50%	6.5%	3.25%
Equity	50%	10.0%	5.00%		50%	8.5%	4.25%
Total	100%		8.50%		100%		7.50%

retirement program funding for a guide to the shareholder's expected rate of return. If the utility stock is selling for a significant premium over book value, it is an indication that the expected return exceeds the required rate of return. The concept of a "fair rate of return" is a return that allows the utility to attract capital without diluting the interest of existing shareholders – that is, a level at which new stock sales would attract the book value of existing shares.[20] This does not preclude a rate of return bonus for achieving energy efficiency goals. For example, the Nevada and Washington commissions have, in the past, allowed increments to the rate of return for cost-effective energy efficiency investments. Other states have permitted performance incentives that have similar effect in exchange for the efficiency services that are valued by customers. As long as the underlying rate of return reflects the utility's marginal cost of capital, this incentive will not create an inappropriate inducement to grow rate base other than cost-effective efficiency investments.

Summary

Rate design is a crucial element of an overall regulatory strategy that fosters energy efficiency and sends appropriate signals about efficient system investment and operations. Rate design is also fully under the control of state regulators. Progressive rate design elements, including low fixed customer charges and usage rates that are cost-based – reflecting high and rising incremental costs – can guide consumers to participate in energy efficiency programs and reduce peak demand. Reflecting all usage-sensitive costs in usage-based prices is crucial to providing accurate price signals. Usage-sensitive costs include the costs of energy, capacity, losses, and all transmission and distribution system investment and expenses necessary to address growth and maintain reliability, as well as wasteful energy use. Optional time-varying pricing enabled by advanced metering infrastructure can help to both lower short-run and long-run system costs and improve system reliability, and it can be coupled with technologies that automate the consumer's response and programs that guide consumers to action. Other options, including revenue decoupling, also can help achieve energy efficiency goals while avoiding attrition in utility net income.

Progressive rate design elements have been in place at many utilities in the U.S. for many years. These include low customer charges, inclining block rates, and revenue decoupling. However, relatively few utilities and commissions have implemented all of these progressive rate design elements. This paper has identified some best practices. A more detailed set of papers is available on the RAP website that addresses most of these elements, and provides examples of utilities and commissions that have adopted these progressive policies.

Endnotes

1 See National Action Plan for Energy Efficiency, *Customer Incentives for Energy Efficiency Through Electric and Natural Gas Rate Design,* prepared by William Prindle, ICF International, Inc., September 2009, available at http://www.epa.gov/cleanenergy/documents/suca/rate_design.pdf.

2 Other charges include taxes, franchise fees, and various rate adjustments. Where electric rates are unbundled, the bill separately itemizes energy, distribution, and transmission charges.

3 Utility franchises exist in many states because the characteristics of the industry (especially high capital costs and declining average costs in the relevant area of demand) for certain essential services are best delivered most stably and efficiently (at lowest average cost) if delivered through a single franchised monopoly utility. Given the franchise award of an exclusive, or nearly exclusive, monopoly, consumers cannot expect to rely on competitive market forces to provide the discipline necessary to assure quality service at fair prices. It is therefore the fundamental role of the utility regulator to function as surrogate for the competitive marketplace in assuring the delivery of quality electric service at fair prices.

4 That is, by pricing lower usage blocks at lower retail prices reflecting, for example, the lower costs of resources for serving historic loads. This is a cost-based justification for inclining block rates – discussed in the section that follows – that addresses the challenge of providing consumers with sound price signals based on forward-looking costs, while recognizing the challenge for regulators in states that allow utilities to recover only existing and potentially historic costs in rates (in states that do not use a future test year to set rates).

5 There are two reasons for including these costs as a separate charge, and at least one important reason for keeping these charges low. Basic charges may be appropriate to include as a separate charge based on issues of fairness, since the failure to treat these costs as a separate charge would precipitate the need to pick them up in other rate elements (e.g., usage sensitive charges). Even low-usage or customers that require only standby service may rightly be expected to pay for the costs of a service connection to the nearest transformer and the ongoing costs of metering and billing. Were they to pay less, then other customers would be asked to bear the burden of costs imposed by these customers. However, in most jurisdictions, low-use customers must pay a line-extension or hook-up fee to cover any distribution investments made by the utility that will not be recovered in usage rates, so including these costs in monthly customer charges can result in double-charging. In jurisdictions where meters and billing services are part of the competitive retail service offering, such a rate design helps ensure competitive fairness. However, fairness and efficiency also dictate that the basic charge be set not higher than necessary to cover the costs that vary with customer numbers. Higher basic charges would simply reduce the most usage-sensitive portion of the rate design, kW and kWh, thereby diminishing the impact of the rate component that is most likely to drive efficient consumer purchases.

6 A few competitive businesses, like Sam's Club and Costco, impose annual membership charges, but they do this in order to differentiate their "wholesale club" business model from ordinary retailers and to discourage "shoppers" as contrasted with "buyers" from their warehouses.

7 As a matter of theory and efficiency, the size and character of the initial block may deserve some more careful consideration. The goal should be to establish overall price signal that minimize the potentially distorting impact of unit prices that are below future costs. Depending on the character of demand (e.g., the load factor and the demand sensitivity) within the initial segments of demand, this may correspond to either a deeper discount with a small block, or a shallow savings with a larger block.

8 Load factor is the ratio of the average load supplied in a period compared to the peak or maximum load in that period. A 600-watt air conditioner with a 15 percent load factor implies that it operates at its full load of 600 watts for 15 percent of the hours in the year (15 percent x 8,760 hours = 1,314 hours). The load factor then is the actual annual usage divided by the consumption that would occur if it operated at full capacity all hours of the year (788.4 kWh)/(5,256 kWh).

9 Studies show that the impacts on peak vary from less than 5 percent to over 50 percent of a customer's load. See Ahmad Faruqui and Ryan Hledik, "Transition to Dynamic Pricing," *Public Utilities Fortnightly,* March 2009.

10 Peak time rebates increase revenue requirements. Because there is no offsetting charge when customers do not reduce demand during a peak time event to cover the cost of the rebates, the all-in rate must be raised to reflect the rebate amount. One analysis estimated revenue requirements would increase by 1.5 percent, assuming the rebate level is set equal to the surcharge calculated for the utility's critical peak price under a critical peak pricing structure. Ahmad Faruqui, Ryan Hledik, Bernie Neenan, and Roger Levy, "Illustrating the Impact of Dynamic Pricing Rates in California," presentation for the Demand Response Research Center Webcast on Jan. 25, 2008, pp. 52-55.

11 Communication with Roger Levy, Levy and Associates. Additional incentives will be needed, adding administrative complexity, cost, and the potential for conflicts.

12 Ahmad Faruqui and Ryan Hledik, "Transition to Dynamic Pricing," *Public Utilities Fortnightly,* March 2009.

13 The results vary considerably by experiment, but typically demonstrate greater response under both CPP pilots and CPP pilots coupled with automating technology. See, See Ahmad Faruqui, Ryan Hledik, and Sanem Sergici , "Rethinking Prices," *Public Utilities Fortnightly,* January 2010.

14 See, for example, Ontario Energy Board Smart Price Pilot, July 2007 that averaged 6 percent conservation effect from pricing programs that were designed to reduce peak (http://www.oeb.gov.on.ca/documents/cases/EB-2004-0205/smartpricepilot/OSPP%20Final%20Report%20-%20Final070726.pdf).

15 Several reasons are given for the conservation effect. First, not all peak reduction results in load shifting, some of it actually displaces load through conservation. Second, dynamic pricing increases awareness of how to use electricity more effectively. Third, consumers receive more feedback on their utilization, which spurs conservation. Id. at 39.

16 See, for example, Strategic Consulting, *PowerCentsDC™ Program: Final Report,* September 2010, available at http://www.powercentsdc.org/ESC%2010-09-08%20PCDC%20Final%20Report%20-%20FINAL.pdf. See also, Ahmad Faruqui, Ryan Hledik, and Sanem Sergici , "Rethinking Prices," *Public Utilities Fortnightly,* January 2010

17 Puget Sound Energy, Docket UE-011570, Exhibit F to Settlement Stipulation.

18 For an explanation of why automatic adjustment clauses for fuel and purchased power make all increased sales profitable for regulated utilities, see David Moskovitz, *Profits and Progress Through Least Cost Planning,* prepared for National Association of Regulatory Utility Commissioners, 1989, pp. 2-4, http://www.raponline.org/docs/RAP_Moskovitz_LeastCostPlanningProfitAndProgress_1989_11.pdf.

19 See Kihm, "The Proper Role of the Cost-of-Equity Concept in Pragmatic Utility Regulation," *Electricity Journal,* December 2007.

20 Utility cost of capital witnesses have a number of logical explanations why the allowed return should exceed the market-required return. The fact that most utility stocks sell at premiums to book value indicates that most regulators have accepted these explanations, so we do not suggest they are not compelling, but nonetheless, this practice results in a powerful incentive to grow rate base.

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