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03 June 2014

Ontario Energy Board
2300 Yonge St., 27th Floor
Toronto, ON
M4P 1E4

Attn: Ms Kirsten Walli
Board Secretary

By electronic filing and e-mail

Dear Ms Walli:

Re: EB-2012-0410 – Rate Design for Electricity Distributors – GEC submission

The Green Energy Coalition (GEC) represents over 125,000 Ontario residents who are members or supporters of its member organizations: the David Suzuki Foundation, Greenpeace Canada, Sierra Club Canada Foundation and WWF-Canada. All of the GEC's member groups are charitable or non-profit organizations active on environmental and energy policy matters.

On behalf of the Green Energy Coalition we offer the following comments on the Board's Draft Report dated March 31st, 2014.

GEC is concerned that the proposed move to a 100% fixed charge for electricity distribution rates will undermine the Conservation First agenda, reducing CDM effectiveness and/or increase its costs of delivery and unfairly subsidize larger, wealthier customers at the expense of smaller, less affluent ratepayers. We believe that the proposal will meet with considerable customer resistance if not tied to energy use.

GEC engaged the services of Mr. William Marcus, principal economist with JBS Energy Inc. to review the draft report and we attach his report.

GEC endorses Mr. Marcus' conclusions:

> Consistent with government policy, fairness and sound economics, rates should provide incentives to conserve and support universal service objectives.
>
> As a result, we recommend retaining a significant portion of the distribution charge as a volumetric rate. We would agree that the bulk of distribution charges should be part of the on-peak rate with a considerably lower off-peak rate for residential and small

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business customers. We would support adopting revenue-per-customer decoupling with a continuous 24 month amortization and 10-year weather normalization to reduce balances. And we would support including more detail on the bill about the time-of-use nature of our proposed distribution rate.

As a result, we do not support the single fixed rate for each class of residential and small business customers (Option 1). It provides strong disincentives against conservation. It does not reflect costs, (both demand-related costs and higher costs to hook up bigger individual customers including single-family homes and three-phase businesses). As a result it is "Robin Hood in Reverse." It will cause small customers (often with lower incomes) to subsidize large customers with higher peak demands and more expensive hook-up equipment. It will sacrifice energy efficiency and raise consumption to give a disproportionate and unjustified break to larger businesses and wealthy individuals. The Gandalf Report indicates that customers don't like it because they (correctly in our view) want to be able to control their bills and save energy. In short we suggest that the Board not do something that the public doesn't like, which will subsidize the rich and make conservation less attractive contrary to Government Policy.

The panel-size rate (option 2) deals with a small portion of the faults of "one-size fits all," but does far less than the Board suggests. It still is a major conservation disincentive, requires the collection of intrusive information (and policing thereafter), and provides only a crude relationship between the customer's demand at peak times and the charge.

While 12-month fixed charges are less desirable than variable rate revenue-per-customer decoupling, we see considerably more promise in a Modified Option 3 than in the other two options. With modifications, the rate would not be designed in tranches but would be continuous and based for 12 months of on-peak use in the three-month peak summer or 6 month summer plus winter period relevant for the specific utility.

We trust that the Board and its staff will find Mr. Marcus' report of assistance.

Sincerely,

David Poch
Cc: All parties

COMMENTS ON THE ONTARIO ENERGY BOARD'S DRAFT REPORT ON RATE DESIGN FOR ELECTRICITY DISTRIBUTORS

(OEB DOCKET EB-2012-0410)

Prepared by:

William B. Marcus

Principal Economist, JBS Energy, Inc.

Prepared for the Green Energy Coalition

June 4, 2014

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I. Overall Policy

It is widely acknowledged that rate design choices should be guided by underlying policy objectives.[1] Traditionally, utility regulators have turned to Bonbright's Principles to inform rate design for regulated monopolies. Published in 1961, James C. Bonbright's *Principles of Public Utility Rates* offers the following 10 principles:

- Rates should be simple, understandable, and acceptable to the public;
- Rates should be stable and predictable and provide bill stability for customers;
- Rates should be practical to implement and easy to interpret;
- Rates should yield the total revenue requirement;
- Rates should provide predictable and stable revenues;
- Rates should be set so as to promote efficient resource use;
- Rates should reflect all costs in the provision of electricity service;
- Rates should be apportioned fairly among customers and customer classes;
- Rates should avoid undue discrimination; and
- Rates should promote innovation in supply and demand.[2]

Bonbright's context, "of course, was traditional price-based regulation."[3] While his principles are well-known, they do not necessarily provide the Board with the most useful

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[1] "The first step is to pin down the ratemaking objectives." Ahmad Faruqui, "Inclining Toward Efficiency, Public Utilities Fortnightly, August 2008, p. 24.

[2] F. Weston, The Regulatory Assistance Project, "Charging for Distribution Utility Services: Issues in Rate Design," December 2000, p. 24 (citing Bonbright, p. 291; Bonbright *et al*., pp. 384-385); The Brattle Group, "Rethinking Rate Design," September 2007, p. 13.

[3] W. Shirley, J. Lazar, and F. Weston, The Regulatory Assistance Project, "Revenue Decoupling: Standards and Criteria" (A Report to the Minnesota Public Utilities Commission), June 2008, p. 18.

analytical framework for evaluating future residential rate design in accordance with Ontario's energy policy goals. In particular two other goals need to be added to this list:

- support for universal service (i.e. affordable for low income customers) and
- promotion of energy efficiency (including peak demand reduction).

Some of these goals may be in conflict and must be balanced. Some of the goals are less important than others within the specific context of residential rate design. We offer some policy commentary on how to weigh and balance conflicting goals while discussing rate design options in more detail below. But this introduction first briefly addresses the additional principles related to universal service and energy efficiency.

Considerations of universal service are important because it is very clear that those with higher incomes – on average, though with wide variation among individual customers – use more energy than small ones, as will be shown below. As a result, the effects of rate design choices on maintaining affordable electricity for lower income customers must be considered. In particular, choices which reduce affordability and create other concerns (e.g., reducing incentives for conservation, not reflecting cost well) should have considerably higher burdens before being accepted.

As for consideration of the promotion of efficiency, in the context of Ontario, we must start with a clear government policy: "Conservation First."

> Ontario has been working for several years to create a culture of conservation in this province. Although the global economic downturn of the past few years dampened electricity demand in Ontario and elsewhere, a shortfall in capacity may emerge as early as 2018. As a result, conservation investments remain a priority for Ontario and conservation should be the first resource considered when planning for the province's electricity needs.[4]

With a "Conservation First" government policy and an emphasis on conservation, that immediately brings several rate design principles into conflict – the principle of revenue

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[4] Ontario Ministry of Energy, "Conservation First: A Renewed Vision for Energy Conservation in Ontario. 2013, p. 1.

stability, the principle that rate design should promote efficiency, and the principle that rates within any given customer class should reflect costs.

Decoupling and increasing fixed charges in rate design are both methods that could insulate the distributors from the financial implications of the "conservation first" policy and the ongoing declines in usage in Ontario.[5] Decoupling and a fixed charge rate design have similar effects for distributors – largely insulating them from the effects of energy efficiency, weather, and the business cycle, but they have very different impacts on customers and incentives for energy efficiency. Out of these two options, 100% fixed rates make efficiency harder and give customers less control over their bills. Accordingly, a decoupling approach utilizing time of use distribution rates would be preferable.

We now examine the options presented by the Board, and discuss additional options.

II. Option 1: Fixed Rate Design

The Board suggests that the fixed rate design would have the economic advantage of reflecting fixed costs in fixed charges and sending price signals to customers that induce appropriate amounts of energy conservation. It would also reduce the disincentive for distributors to deliver energy efficiency services.[6]

We must respectfully disagree. Our disagreement has several bases.

Within residential and small commercial classes, a fully fixed rate design does not reflect costs. Second, reflection of costs in small customer rate design is not of paramount importance. Universal Service and conservation considerations are arguably more important – particularly in a Conservation First policy environment.

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[5] Navigant Consulting Limited, Analysis Investigating Revenue Decoupling for Electricity and Natural Gas Distributors in Ontario, March 26, 2014, p. 45.

[6] EB 2012-0410, Report of the Board April, 2014, (Henceforth "Board Report"),

A. Fully Fixed Charges Do Not Reflect Costs

1. One Size Does Not Fit All

Specifically, a fixed rate design for the entire distribution system does not reflect costs. The primary reason is that large portions of the system were built to meet demand, and many *incremental* investments are demand-related. The demands for which the system is built are local area demands – summer peak in large parts of Ontario (a change over the last 25 years ago) but winter peaking in some regions. Except for lines very close to the customer, the system is not built to meet individual customer demands, and even then residential demands are considerably diversified down to the final line transformer.

Customers have load factors that vary in predictable ways. Those customers who use a smaller percentage of their energy during peak periods tend to have better load factors and need less of the demand-related distribution system than those who use more energy. In the residential class, apartment dwellers have been shown to have better load factors than single-family homeowners in several jurisdictions.[7] Customers with less emphasis on electric space conditioning (gas heat and no air conditioners or room air conditioners) will also have better load factors. These customers are also likely to be smaller. Thus distribution costs to serve individual customers actually vary with the size and usage of the customer.

But even connection costs such as transformers and service drops vary with customer configurations. It is cheaper to serve residential customers in apartments than customers in single family homes, because service drops, transformers, and primary distribution investments closest to the customer have economies of scale and are much lower for apartment dwellers. The size of a service drop is also related to the demand of the

[7] W. Marcus and G. Ruszovan, Know Your Customers: A Review of Load Research Data and Economic, Demographic, and Appliance Saturation Characteristics of California Utility Residential Customers. December, 2007, pp. 6-12 (Southern California Edison), 36-41 (San Diego Gas and Electric).

customer. This relatively obvious fact is ignored in cost allocation and rate design by most utilities, with the exception of those in Nevada[8] and California.[9]

With a small business class up to 50 kW, there are massive differences in scope between small single-phase customers and large three-phase customers. Not only may the demand be 10 times as great for a large customer than a small one, but the equipment needed to serve a 49 kW three-phase customer (including the meter as well as the service and transformer) is far more expensive than for small single-phase customers, who may require similar equipment to residential customers. [10]

It is absolutely unavoidable from this perspective to see a single residential customer charge or a single customer charge for small business customers up to 50 kW as anything other than "Robin Hood in Reverse." We know apartment dwellers have lower distribution cost responsibility than single-family homeowners, both because of better load factors and cheaper equipment per customer. We know the smallest business customers have much lower hook-up costs, with cheaper transformers, services and meters than larger three-phase customers. By averaging all these costs, the Board would knowingly be choosing to force small customers to subsidize large ones.

At the very least, if it is going to adopt a fixed charge for all distribution service contrary to our recommendation, the Board must not only maintain density divisions (which we understand Hydro One does) but divide the residential class (at least for high-density areas within Hydro One and for the urban distributors) into apartments and single-family homeowners. It should also divide the small business class between single-phase and

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[8] Prepared Testimony of Timothy Pollard on behalf of Sierra Pacific Power Company in Docket 13-06003, Exhibit Pollard-Direct-2, pages 6-7 shows customer costs of facilities, service drops, meters, billing, and customer service of $310 for single-family customers and $146 for multi-family customers. Multifamily customers are treated as a Separate rate class, and their load factor is also higher than single-family customers. See Sierra Pacific Power Company Docket 13-06003, Schedule O.

[9] See as one example Southern California Edison Company, Marginal Cost Testimony (Updated), California Public Utilities Commission App. 11-06-007, p. 33.

[10] Southern California Edison company finds that the fixed costs of providing a transformer, service drop, metering, and billing services (excluding the rest of the distribution system) are more than twice as great for a three-phase customer under 20 kW as for a single-phase customer under 20 kW. Southern California Edison Company, Marginal Cost Testimony (Updated), California Public Utilities Commission App. 11-06-007, p. 32.

three-phase customers. Otherwise the Board will require poor people in apartments to pay more so that the better off can pay less. And it would require the smallest businesses to pay huge amounts to be connected to the system so that larger three-phase customers can be subsidized.

2. The Minimum Distribution System Has its Own Flaws

In addition, the OEB's minimum distribution system (which underlies the Board's current cost allocation model and is relied upon as support for higher fixed charges in the current HONI application, EB-2013-0416) has practical and analytical flaws for setting customer charges and should not be utilized to justify increased fixed charges.

First, it equates the costs of spanning the system's area with customer costs. However, this is a leap of faith. The correlation between area and the number of customers is relatively weak (except in fairly uniform and highly rural service areas). The distribution wires per customer required to serve an apartment building are considerably less than the wires required to serve a house on acreage or a school or shopping center on a square block or more.

More importantly, if one could hypothesize such a concept as serving customers without a significant demand, the area would not be served at utility expense. Most utilities' line extension rules provide that service is extended at utility expense based on the revenue to be generated from that service (either explicitly or implicitly – as with a dollars-per-customer allowance based on class average revenue). If revenue is not adequate, service is only extended at the cost of the applicant. Thus, fundamentally, the expansion of the distribution system as it is actually built is driven by demand, not the mere existence of customers.

Second, assignment of an equal amount of the minimum system to each individual customer makes no sense. A large store with street frontage on an entire block would clearly need more meters of wire (and more poles if served from overhead) to connect it than would each of (for example) 50 individual residential customers in an apartment building on the same sized block. Yet under the mathematics of the minimum system proposal each apartment dweller would be assigned the same number of meters of the

minimum distribution system as the store, not one-fiftieth as much. A related failing of the minimum system can be examined when we look at a primary distribution line connecting two towns in a rural area of the system. That line is necessary to serve demand in those communities. The same connection would be needed just as much if there were one industrial customer located at the connection point with a demand equal to the whole town's demand or there were 1,000 residential and small commercial customers. Yet the minimum system method would charge the hypothetical industrial customer 0.1% as much as the hypothetical 1000 small customers in the hypothetical second town.

Additionally, the minimum system method double-counts the costs of serving low-use customers, both across customer classes for cost allocation and within customer classes if used for rate design. In a nutshell, the analytical problem arises because minimum system method often develops a hypothetical utility system made up of poles, wires, and transformers that can carry a significant amount of demand. The minimum system is assigned to all customers based on an equal number of dollars and meters of line per customer. If that is done, then it is wrong to allocate the remaining demand-related portion of the system by the total system demand. Analytically, if the minimum system is used as a customer cost, it would be necessary to use a demand allocator that would give each customer class credit for that portion of the demand (an equal number of kilowatts per customer) that can be carried by the minimum system.

Small customers are overcharged by any minimum system method if it does not include an adequate credit for the demand carried by the minimum system, because the minimum system carries a much larger percentage of the demand of small residential customers than it does of the demand of large customers.[11]

While we have not analyzed the specifics of the Ontario system for purposes of preparing these comments (and plan to provide further specific analysis in the Hydro One case), we

[11] It is our understanding that the OEB in the past has developed a minimum system that is intended to carry 400 watts per customer, and that the demand related costs have been subtracted from the customer costs. If the system components actually could only serve 400 watts per customer (a question discussed below), this concern may be addressed.

have made similar analyses for poles and conductors (wires) for a number of utilities. A number of technical factors come into play. The carrying capacity of the minimum sized poles and conductor is dependent on a number of factors including line length, reactive power, and the specific voltage of primary distribution lines. Nevertheless, in many cases, the smallest single-phase primary overhead conductor could carry 1000-2500 kVA, which is a significant portion of demand of a local area.[12]

There is a different technique that can be used called a "zero intercept" method which uses regression equations relating cost of conductor or other equipment to a constant and the size of the equipment. It essentially attempts to find the cost of a component of zero size (zero-amp wire or zero-meter tall pole). These methods attempt to avoid the double-counting of demand. It has somewhat less analytical problems than a minimum system and generally produces lower customer percentages. But the zero-intercept method often finds the cost of a zero-amp conductor or a zero-meter pole would not be statistically different than zero. In other words, all costs are demand-related.[13]

These critiques of the minimum system are by no means new or path-breaking. Serious critiques of the minimum system method date back over 50 years. Professor Bonbright

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[12] For example, we present information for several utilities analyzed recently. Duke Energy North Carolina, the utility's smallest single-phase primary overhead conductor could carry 2085 kVA (139 amps X 15 kV). It's smallest single-phase primary underground conductor could carry 2550 kVA. Prepared Testimony of William B. Marcus on behalf of the North Carolina Waste Awareness and Reduction Network (NC WARN), North Carolina Utilities Commission Docket No. E-7, Sub 126, pp. 35-36, citing NC WARN Data Requests 1-45 and 1-47. For Oklahoma Gas and Electric Company, the smallest single-phase primary conductor carries 1680 kVA. Prepared Testimony of William B. Marcus on behalf of the Attorney General, Arkansas Public Service Commission Docket 06-070-U, October 2006, pp. 35-36, citing Attorney General Data Request 1-44. A recent analysis of Entergy Arkansas, Inc. (where the Arkansas Public Service Commission rejected the minimum system method) found that EAI's smallest single-phase conductor could carry nearly1500 kVA (119 summer amps X 12 kV). The smallest poles in common use today could carry wires with up to 744 amps (over 8000 kVa at primary distribution). Surrebuttal Testimony of William B. Marcus on behalf of the Attorney General, Arkansas Public Service Commission Docket 13-028-U, September, 2013, p. 58, citing Attorney General Data Requests 1-39 and 1-41.

[13] A detailed analysis including equations, showing zero-intercept costs that were 100% demand-related for poles and wires was prepared for Empire District Electric Company in Prepared Testimony of William B. Marcus on behalf of he Attorney General, Arkansas PSC Docket 10-052-U, pp. 96-100. See also (for Duke Energy) Prepared Testimony of William B. Marcus on behalf of the North Carolina Waste Awareness and Reduction Network (NC WARN), North Carolina Utilities Commission Docket No. E-7, Sub 126, pp. 35-36, citing NC WARN Data Requests 1-45 and 1-47 and for Oklahoma Gas and Electric Company, Prepared Testimony of William B. Marcus on behalf of the Attorney General, Arkansas Public Service Commission Docket 06-070-U, October 2006, pp. 35-36, citing Attorney General Data Request 1-44.

recognized the inaccuracies of treating minimum system costs as customer costs in his **1961** edition of Principles of Public Utility Regulation.[14] His preferred option was to recognize that minimum system costs were neither demand nor customer costs but were unallocable. (See Attachment 1) He adds:

> And this is the disposition that it would probably receive in an estimate of long-run marginal costs. But the fully distributed cost analyst dare not avail himself of this solution, since he is the prisoner of his own assumption that "the sum of the parts equals the whole." He is therefore under impelling pressure to "fudge" his cost apportionment by using the category of customer costs as a dumping ground for costs that he cannot plausibly impute to any of his other cost categories.

A seminal Public Utilities Fortnightly article written 30 years ago by George Sterzinger provides a further clear exposition of the problems with the minimum system method. Attachment 2 is a copy of the article. Dr. Sterzinger not only opposed use of the minimum distribution system method because of the confusion of area and customer costs, but he was the first to bring to the forefront the significant criticism that the minimum system method clearly overcharges small customers, because the minimum system can carry a significant portion of the residential class's demand.

Thus, for the reasons discussed above, a minimum system method does not provide a sound basis for establishing a customer charge, as it establishes an equal charge for unequally situated customers and often fails to reflect the demand served by the minimum system.

3. Fixed Cost Rate Design is Based on a Theory that Markets are Efficient. Energy Efficiency Policy is Based on the Known Reality that Markets are Inefficient.

While the Board suggests that it is important for rates to reflect cost and reflect that delivery costs are fixed, even if we were to concede these points, we do not agree with the fixed rate design proposed by the Board.

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[14] The current edition, revised by others after his death, omits this criticism.

This disagreement comes because we place more weight on both promoting conservation and peak load reduction and on promoting universal service than we do on reflecting cost considerations for intra-class rate design in residential and small business classes.

We note that the whole idea that proper price signals lead to economic efficiency and appropriate amounts of conservation is in direct contradiction to the current Government Policy. If the economics of electricity consumption would run perfectly if we just had the right prices, then we would not need a "Conservation First" policy, because the market by itself would place us in the best of all possible worlds and anything that we would do would make things worse.[15]

Many economists, assume that the world runs like a Swiss watch without market imperfections. If we just "get the prices right" consumers will "do the right thing." rather than "conserving too much." Under this view, there is allegedly no reason to encourage conservation unless one is concerned about externalities such as global warming, nuclear risk, or depletion of natural resources. Whatever customers do in response to price is deemed to be economically rational.

The Board and the Government of Ontario both know that this view of the world is not true; otherwise it would not be spending significant ratepayer money to offer expanded energy efficiency programs.

In particular, there are a series of known market failures and institutional barriers that prevent cost-effective efficiency investments including, but not limited to:

- split incentives (where one party pays for the investment and the other pays the utility bill), such as between landlords and tenants and similarly between new home builders and the first owners;

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[15] In other contexts than Ontario, utility witnesses have actually claimed that high energy charges cause consumers to conserve too much. See for example, Supplemental and Revised Direct Testimony of H. Edwin Overcast on behalf of Empire District Electric Company, Arkansas Public Service Commission Docket 10-052-U, p. 29, which states "If fixed costs were reduced and more revenue recovered from energy charges, resources would be wasted trying to conserve more energy than the efficient level." See also, Severin Borenstein, "Regional and Income Distribution Effects of Alternative Retail Electricity Tariffs," Haas Workpaper #225, October 2011, p. 1.

- tenure versus appliance life (a residential customer may not believe that he or she can gain adequate benefits from an investment if the length of residency is short or uncertain), even though future customers who occupy the premises would receive benefits over the life of the investment;
- lack of information by customers on investment choices with different energy use, their effectiveness, and their impact on energy costs;
- lost opportunities (conservation investments that must be made at a particular time, when a building is built or an appliance is replaced) or they are no longer cost-effective if not made at precisely the right time.
- lack of capital to spend on efficiency investments.
- The fact that carbon emissions (and externalities in general) are largely unpriced, even though they are likely to have a non-zero value in the relatively near future, which makes short-run decision-making imperfect.

These considerations have led to the development of appliance and building standards and to utility efficiency and demand management programs. It is clear that rate design cannot induce sufficient conservation by itself, but it has at least some impact in increasing the amount of cost-effective conservation that is pursued.

Given the Government and Board policies that promote the development of significant energy efficiency programs, the Board should not be driving with one foot on the gas (efficiency programs) and the other foot on the brake (high fixed charge rate design). Rate design and efficiency policy should be harmonized, not at cross-purposes with each other.

High customer charges will render energy conservation programs less efficient or more costly or both. All else being equal, an increased residential customer charge will decrease the cost-effectiveness of measures that save electricity. This will also decrease the effectiveness of energy efficiency programs operated by the utility by making it less cost-effective for customers to conserve. The end result of having rate design compete with efficiency programs is either higher rebates raising program costs or lower penetration of the programs or both. Raising fixed charges wastes ratepayer money spent on efficiency programs.

On the other hand, the argument might be made that the incentives to the distribution utility must also be harmonized with a conservation first agenda, and decoupling assists in that regard. But the way to harmonize those incentives is do adopt a simpler and broader decoupling measure than the current Lost Revenue Adjustment Clause, which we will discuss below, or if adopting some kind of fixed charge, make a significant portion of it demand-related (see Modified Option 3).

4. Fixed Charges Blunt Conservation Policy and Raise Usage

There are two ways to look at this issue, which we will do schematically and illustratively in these comments.

The Simple Payback on a Given Conservation Measure is WorsenedAssume we have an energy efficiency program that is cost-effective to the consumer with a simple payback of 4 years under current rate design (assume 25% of costs are distribution costs; half are collected in fixed charges).[16] Now we move 1/7th of the variable costs into fixed charges (the other 12.5% of distribution costs divided by the 87.5% of total costs collected variably before the rate design shift). Variable rates drop by about 14%, and the payback increases to 4.67 years.

Add one more feature. Utility/government programs subsidized the efficiency program to a 3 year payback to induce a much larger number of customers to acquire the measure. This subsidy was 25% of the cost of the measure. With the rate design shift, either the existing subsidized program now has a 3.5 year payback (not what was intended when it was designed) and fewer customers take up the measure, or the subsidy has to be increased from 25% to about 36% of the cost of the measure to get back to a three year payback.

Again, this is driving with one foot on the accelerator and one foot on the brake, and this is why increasing customer charges to reduce energy charges is wasteful of government and ratepayer money.

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[16] Board Report, pp. 3, 7. (Note that there is significant variation between utilities, especially between HONI and urban utilities)

Consumption will Increase because of the Elasticity of Total Demand

Again, assume that there is a current rate design where 25% of costs are distribution costs; half are collected in fixed charges). We again move 1/7th of the variable costs into fixed charges (the other 12.5% of distribution costs divided by the 87.5% of total costs collected variably before the rate design shift). Variable rates drop by about 14%. This will cause electricity consumption to increase. The amount depends on the elasticity of demand, which is relatively low in the short-run but may be higher in the longer term, when new investments are made – particularly with efficiency programs supporting them.

A 14% decrease to the variable rate could raise consumption in the short run by 1 to 4% (based on elasticities of 0.075 to 0.3)[17], with potential larger long-run impacts if energy efficiency investments are reduced.

B. Universal Service

While there is a wide variety among customers, low-income customers in the aggregate use less energy than higher income customers. Therefore, low income customers will be more affected by rate increases arising from shifting costs from variable rates to fixed charges, while, on average, higher income customers will see rate decreases, as the energy charge reduction exceeds the customer charge increase. Data from Statistics Canada's CANSIM data base (extracted from Table 203-0322) shows the following information on electricity and energy expenditures for Canada and Ontario by income quintiles for 2012. These data demonstrate the strong relationship between income and electricity use.

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[17] 14% X 0.075 = 1.05%; 14% X 0.3 = 4.2%. The low end of the range comes from testimony of Dr. Ren Orans for BC Hydro cited in BC Hydro, Residential Inclining Block Rate Application, Final Argument, Project 3698504, July 9, 2008, p. 21. The higher end of the range is from Evidence of Jim Lazar, Consulting Economist on behalf of Time to Respect Earth's Ecosystems [TREE] and Resource Conservation Manitoba [RCM] in Manitoba Hydro's 2004 General Rate Case, p. 11 and Exhibits JL-3 and JL-4.

	All Expenditures	Electricity	Natural Gas	Other Fuel	Total energy
Canada					
All	$ 75,543	$ 1,277	$ 513	$ 188	$ 1,978
Lowest quintile	$ 29,921	$ 718	$ 214	$ 123	$ 1,055
2nd	$ 43,507	$ 1,038	$ 350	$ 174	$ 1,562
3rd	$ 64,008	$ 1,257	$ 448	$ 218	$ 1,923
4th	$ 88,061	$ 1,493	$ 682	$ 199	$ 2,374
highest	$ 151,506	$ 1,880	$ 869	$ 226	$ 2,975
Ontario					
All	$ 78,495	$ 1,181	$ 755	$ 135	$ 2,071
Lowest quintile	$ 31,121	$ 527	$ 313	$ 68	$ 908
2nd	$ 45,091	$ 868	$ 505	$ 134	$ 1,507
3rd	$ 65,898	$ 1,189	$ 713	$ 177	$ 2,079
4th	$ 92,495	$ 1,467	$ 1,083	$ 117	$ 2,667
highest	$ 156,989	$ 1,847	$ 1,158	$ 177	$ 3,182

US data from both the Bureau of Labor Statistics and the Energy Information Administration shows the same phenomena.[18] US national data from the BLS are provided below for reference.

[18] http://www.bls.gov/cex/2011/Standard/income.xls for national data and http://www.bls.gov/cex/2011/Standard/higherincome.xls for disaggregated data above $70,000 . The EIA survey is described at www.eia.doe.gov/emeu/recs/contents.html . "Microdata" (individual survey records) can be accessed from www.eia.doe.gov/emeu/recs/recspubuse05/pubuse05.html.

	National	
	Gas	Electricity
All Consumers	359	1,388
Less than $5,000	180	825
$5,000 to $9,999	178	902
$10,000 to $14,999	204	954
$15,000 to $19,999	243	1,101
$20,000 to $29,999	261	1,192
$30,000 to $39,999	305	1,295
$40,000 to $49,999	351	1,367
$50,000 to $69,999	344	1,417
$70,000 and more	*518*	*1,749*
$70,000 to $79,999	421	1,538
$80,000 to $99,999	435	1,580
$100,000 and more	*586*	*1,891*
$100000 to $119,999	491	1,722
$120,000 to $149,999	553	1,787
$150,000 and more	685	2,103

C. Customer Acceptance is Problematic

The focus groups conducted by the Gandalf Group indicate that customers do not like fixed charges. We quote:

> A more widely shared concern was the proposal to move to 12 months of fixed charges. It helped modestly to explain that system costs are relatively fixed month to month as a justification for fixed charges. That argument was somewhat undermined by the proposal to peg charges at different levels leaving people confused as to whether costs are variable or fixed and whether charges should be too.
>
> Fundamentally there is a concern about cost of living pressures here and an **engrained acceptance that a substantial portion of costs or bills should be variable** (perhaps more since the introduction of TOU). This specific proposal appears to preclude savings they believe they are working to achieve with steady reductions in use under TOU. Finally, a fixed charge approach over 12 months seems like a higher burden. [emphasis added][19]

Some people in the focus groups picked up on the conservation incentive issues that we discussed more theoretically above. Concerns noted by Gandalf's focus group participants included:

[19] The Gandalf Group, Ontario Energy Board Distribution Charge Focus Groups, Final Report (Hence "Gandalf Report") October 9, 2013, pp. 4-5.

- The fact that many assume they will seek efficiencies in the course of each year and that this will forestall the benefit or reduce the payback of those.
- Others believed that if we were encouraging reductions in peak consumption, along the lines of TOU pricing that they should be incentivized either to the full extent or in the way they are accustomed to.[20]

D. Conclusion on Option 1

In sum, we see little to recommend in Option 1. Essentially, the Board is proposing to take an action that customers do not understand and do not like because it supposedly reflects economic theory but in fact ignores much of the real economics. It is both unfair and economically inefficient.

This action is proposed despite the fact that fixed charges do not reflect cost adequately and because they do not reflect cost will cause lower income people and apartment dwellers to subsidize higher income residential customers with higher demand and more costly hook-ups and will cause smaller single-phase businesses to subsidize larger businesses with higher demand and more expensive three-phase equipment.

This action is proposed even though (1) conservation incentives will be reduced and electricity consumption is likely to rise contrary to Government policy, (2) market pricing (which is supposed to justify the theory of fixed costs) is imperfect in many respects raising serious barriers to energy conservation, and creates the need for energy efficiency incentives. The Board and the Government will be driving with one foot on the brake (fixed charges) and one foot on the accelerator (energy efficiency programmes and incentives). This is wasteful.

III. Option 2: Panel Size

Nearly all of the comments provided regarding Option 1 apply to Option 2, so they will not be repeated. Only differences among the options will be highlighted.

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[20] Id., page 10.

Option 2 might be mildly better than a fully fixed charge because panel size would (inadvertently) capture some of the cost differences between apartments and houses and to a lesser extent between bigger and smaller houses, as well as better distinguishing between larger and smaller businesses.

Data on panel sizes are not available to many of the utilities, and customers might believe it intrusive to give data to the utilities.

More importantly, the Board points out that there is a theoretical potential to conserve to reduce panel size in new construction.[21] We have several comments which suggest that argument is at best highly overstated. First, panel size is an imperfect measure of demand. The demand of an individual customer might theoretically be affected by panel size. However, there is no hard evidence that it affects demand in real life because panels are usually oversized either by builders who standardize their approach, or because of the unpleasant consequences of tripping the main breaker on the house under unusual conditions, or as a low cost way of ensuring adequate capacity if uses are subsequently expanded. Moreover, the individual customer's demand has very little impact on distribution planning. It is the diversified demand of large numbers of customers that matters to the planners (see below).

It is telling that there has been no evidence of any outreach to builders from utilities trying to affect panel size even in advance of this rate design. It is reasonable to assume that the utilities themselves do not see panel size as a key means of promoting conservation.

More importantly panel size is largely fixed in existing homes and businesses, even if a customer reduces demand, so that these fixed rates would not in most cases provide an incentive for conservation. Because conservation among existing customers would free up distribution circuit capacity, which can be used by new customers or to serve new

[21] Board Report, p.26.

growth among other existing customers, a fixed charge rate design based on panel size which fails to provide an adequate conservation signal is economically inefficient.[22]

In sum, if costs are based on demand, then the Board should actually base costs on demand rather than using a crude ineffective proxy like panel size. This point brings us to option 3.

IV. Option 3 – Charge Tiered by Peak Use

The option of basing 12 months of peak demand on some type of peak usage has more promise, although the tiered charges with fixed boundaries proposed by the Board[23] blunt the price signals and create problems for customers near boundaries.

We caution against designing rates with very short period demands (e.g., the highest 15 minutes or hour). Very short period demands essentially force perfection on customers in managing all aspects of their loads. The Gandalf focus groups reflected concerns about maximum usage charges in addition to TOU rates that customers understand:

> The concept of maximum use during peak times is difficult for people to understand and raised concern among a few. There is no template for measuring maximum use that people are used to in the way they understand TOU. It was not obvious how this would be calculated.
>
> Without precise details of this there was concern expressed by some that small lapses in their conservation efforts will mean they will have to pay a high price for that (even if they conserve diligently on the vast majority of days during peak times). So there will be questions of fairness if they have conserved on the vast majority of days during peak demand times and essentially helped to reduce peak consumption. [24]

Second and more importantly, the non-coincident peak of an individual residential customer has only limited relationship to system peaks or even circuit peaks after

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[22] Manitoba Hydro had an extra customer charge based on panel size at one time. The comments regarding existing customers were adapted from Evidence of Jim Lazar, on behalf of TREE and RCM in Manitoba Hydro's 2004 General Rate Case, p. 10.

[23] Board Report, p. 27.

[24] Gandalf Report page 9.

controlling for energy use.[25] There are also differences in coincidence between apartments (where weather-sensitive loads are a lower percentage of total energy use) and single-family homes, that a maximum demand charge cannot be designed to deal with.[26]

Third is the issue of how to deal with people who move and may have different usage patterns than the former residents.

We would propose two alternatives to revise option 3.

Our preference would be not to set a fixed charge at all but would collect 75% of distribution costs not collected through existing customer charges in volumetric on-peak period rates, and the remaining 25% across the year (to reflect that non-coincident demands may affect distribution design very close to the customer). This option would be used together with modified decoupling approaches below.

The second alternative (which would better conform to the Board's stated preference for a fixed charge) would set a fixed charge for each customer that would apply until the end of the next season based on kWh usage in the on-peak hours of the highest peak months (June-August in summer peaking areas, both June-August and December-February in winter-peaking areas). These data could be downloaded readily from AMI meters. This would yield a charge where demand costs for each customer would be based on costs in high-load hours that cause distribution system construction.

Such charges would be preferable to maximum demand charges because they do not force levels of perfection on the customer that would arise from a maximum demand charge and we would not end up with a rate that would not be cost-based because of

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[25] W. Marcus and G. Ruszovan, Know Your Customers: A Review of Load Research Data and Economic, Demographic, and Appliance Saturation Characteristics of California Utility Residential Customers. December, 2007, pp. 6-12, 36-41.

[26] Southern California Edison Company, Marginal Cost Testimony (Updated), California Public Utilities Commission App. 11-06-007, Appendix B, shows that average demand at the time of a 12 kV feeder peak is 33% of the sum of individual residential customers' non-coincident demands for single-family customers and 26% for multi-family customers. Similar results are found for substations and subtransmission voltages.

weak coincidence between the customer's maximum demand and the system (or local distribution area) demand.

The rate could be set from October to October based on the previous summer (or April to April based on the previous winter) to collect a specific revenue requirement for each customer based on the peak kWh actually used once all the data have become available. Because the revenue requirement apportioned to each customer is based on past kWh usage, further decoupling would not be needed. Under this alternative, customers could be given consistent messages that peak period conservation is doubly important – both to reduce the need for high cost generation but to reduce distribution peaks (which will reduce future distribution construction).

V. Traditional Decoupling of Revenue from Sales

We discuss traditional decoupling mechanisms briefly because we believe that such mechanisms are preferable to fixed charge pricing for distribution systems. We understand that the Lost Revenue Adjustment Mechanism is burdensome, and would propose a broader and simpler mechanism.

Attachment 3 is a detailed paper by the Regulatory Assistance Project (RAP) on a variety of decoupling options for the Board's consideration. We particularly commend the Board's attention to the revenue-per-customer decoupling method, which is far simpler than the LRAM. That method could be used with our preferred method of distribution variable rate recovery –through volumetric charges that are largely but not entirely assigned to peak periods.

We respond to the concern that a decoupling mechanism might build up a large balance with two comments.

First, we suggest that the balance be continuously and automatically amortized on a 24 month basis with an appropriate lag, 30-60 days in arrears (i.e., 1/24th of balance through January is amortized starting in March or April).

Second, with decoupled revenue, if not already the case, it may make sense to change weather normalization to a shorter normal period (e.g., 10 years) which could reduce

variance due to weather and thus balance build-ups. That change was made for gas decoupling in California in the late 1990s.

VI. Conclusion

Consistent with government policy, fairness and sound economics, rates should provide incentives to conserve and support universal service objectives.

As a result, we recommend retaining a significant portion of the distribution charge as a volumetric rate. We would agree that the bulk of distribution charges should be part of the on-peak rate with a considerably lower off-peak rate for residential and small business customers. We would support adopting revenue-per-customer decoupling with a continuous 24 month amortization and 10-year weather normalization to reduce balances. And we would support including more detail on the bill about the time-of-use nature of our proposed distribution rate.

As a result, we do not support the single fixed rate for each class of residential and small business customers (Option 1). It provides strong disincentives against conservation. It does not reflect costs, (both demand-related costs and higher costs to hook up bigger individual customers including single-family homes and three-phase businesses). As a result it is "Robin Hood in Reverse." It will cause small customers (often with lower incomes) to subsidize large customers with higher peak demands and more expensive hook-up equipment. It will sacrifice energy efficiency and raise consumption to give a disproportionate and unjustified break to larger businesses and wealthy individuals. The Gandalf Report indicates that customers don't like it because they (correctly in our view) want to be able to control their bills and save energy. In short we suggest that the Board not do something that the public doesn't like, which will subsidize the rich and make conservation less attractive contrary to Government Policy.[27]

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[27] If the board does go in this direction, it should break the residential class into apartments and single-family homes when feasible and should break the small commercial class into cheaper single-phase customers and more expensive three-phase customers

The panel-size rate (option 2) deals with a small portion of the faults of "one-size fits all," but does far less than the Board suggests. It still is a major conservation disincentive, requires the collection of intrusive information (and policing thereafter), and provides only a crude relationship between the customer's demand at peak times and the charge.

While 12-month fixed charges are less desirable than variable rate revenue-per-customer decoupling, we see considerably more promise in a Modified Option 3 than in the other two options.[28] With modifications, the rate would not be designed in tranches but would be continuous and based for 12 months of on-peak use in the three-month peak summer or 6 month summer plus winter period relevant for the specific utility.

[28] We strongly oppose any rate based on the individual customer's short-interval maximum demand, because that rate design is not understood by residential customers, is hard for the customer to influence (demanding perfection in conservation efforts), and is not coincident with the system or local area demand.

THREE-PART ANALYSIS OF THE COSTS OF AN ELECTRIC UTILITY BUSINESS

In order to simplify the exposition of a typical fully apportioned cost analysis, let us assume the application of the analysis to an electric utility company supplying a single city with power generated by its own steam-generation plant. Let us also assume the existence of only one class or type of service, all of which is supplied at the same voltage, phase, etc. to residential, commercial, and industrial customers. This latter assumption will permit us to center attention on the most controversial aspect of modern public utility cost analysis—the distinction among costs that are functions of outputs of the same service measured along different dimensions.

Since the company under review is supplying what we are here regarding as only one kind of service, we might suppose that the problem of total cost apportionment would be very simple; indeed, that it would be limited to a finding of the total annual operating and capital costs of the business, followed by a calculation of this total in terms of annual cost per kilowatt-hour of consumption. In fact, however, the problem is not so simple. For a statement of costs per kilowatt-hour would ignore the fact that many of these costs are not a function of kilowatt-hour output (or consumption) of energy. A recognition of multiple cost functions is therefore required.

The simplest division, and the one most frequently used (with subdivisions) in gas and electric rate cases, is a threefold division of the total operating and capital costs into "customer costs," "energy" or "volumetric costs," and "demand" or "capacity" costs.[7] If this threefold division of costs were to have its counterpart in the

[7] Other cost breakdowns, such as those allowing for the power factor, for voltage differences, for distances between points of generation and points of consumption, and for the customer-density factor, have been used to a limited extent. Compare Vickrey's selection of six parameters in order to approximate the response of the operating costs of the New York City Rapid Transit System to various changes in service and traffic: Train miles; car miles; maximum number of cars in service; number of passengers carried; number of passengers carried during the peak hour; and the layout of the system, consisting of the number of route miles, number of stations, etc. William S. Vickrey, *The Revision of the Rapid Transit Fare Structure of the City of New York*. Technical Monograph No. Three, Finance Project, Mayor's Committee on Management Survey of the City of New York, Feb., 1952, p. 8.

actual rates of charge for service, as it actually does have in some rates, there would result a three-part rate for any one class of service. For example, the monthly bill of a residential consumer might be the sum of a $1 customer charge, a $5 charge for 250 kilowatt-hours of energy at 2¢ per kilowatt-hour, and a $2 charge for a maximum demand of 2 kilowatts during the month at the rate of $1 per kilowatt—a total bill of $8 for that month. But our present interest lies in the measurement of costs of service, and only indirectly in rates that may or may not be designed to cover these costs. Let us therefore consider each of the three types of cost in turn, recognizing that this simplified classification is used only for illustrative purposes; costs actually vary in much more complex ways.

1. THE CUSTOMER COSTS

These are those operating and capital costs found to vary with number of customers regardless, or almost regardless, of power consumption. Included as a minimum are the costs of metering and billing along with whatever other expenses the company must incur in taking on another consumer. These minimum costs may come to $1 per month, more or less, for residential and small commercial customers, although they are substantially higher for large industrial users, who require more costly connections and metering devices. While costs on this order are sometimes separately charged for in residential and commercial rates, in the form of a mere "service charge," they are more frequently wholly or partly covered by a minimum charge which entitles the consumer to a very small amount of gas or electricity with no further payment.

But the really controversial aspect of customer-cost imputation arises because of the cost analyst's frequent practice of including, not just those costs that can be definitely earmarked as incurred for the benefit of specific customers but also a substantial fraction of the annual maintenance and capital costs of the secondary (low-voltage) distribution system—a fraction equal to the estimated annual costs of a hypothetical system of minimum capacity. This minimum capacity is sometimes determined by the smallest sizes of conductors deemed adequate to maintain voltage and to keep from falling of their own weight. In any case, the annual costs of this phantom, minimum-sized distribution system are treated as

customer costs and are deducted from the annual costs of the existing system, only the balance being included among those demand-related costs to be mentioned in the following section. Their inclusion among the customer costs is defended on the ground that, since they vary directly with the area of the distribution system (or else with the lengths of the distribution lines, depending on the type of distribution system), they therefore vary indirectly with the number of customers.

What this last-named cost imputation overlooks, of course, is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customers per linear mile or per square mile). Indeed, if the company's entire service area stays fixed, an increase in number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system.

While, for the reason just suggested, the inclusion of the costs of a minimum-sized distribution system among the customer-related costs seems to me clearly indefensible,[8] its exclusion from the demand-related costs stands on much firmer ground. For this exclusion makes more plausible the assumption that the *remaining* cost of the secondary distribution system is a cost which varies continuously (and, perhaps, even more or less directly) with the maximum demand imposed on this system as measured by peak load.

But if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs for the reason just given, while it is also denied a place among the customer costs for the reason stated previously, to which cost function does it then belong? The only defensible answer, in my opinion, is that it belongs to none of them. Instead, it should be recognized as a strictly unallocable portion of total costs. And this is the disposition that it would probably receive in an estimate of long-run marginal costs. But the fully-distributed cost analyst dare not avail

[8] This is in accord with the views of Hubert F. Havlik: *Service Charges in Gas and Electric Rates* (New York, 1938), Chap. 8 and Appendix A. Allocation, in whole or in part, would be at least theoretically possible if a customer-density factor meter were added to the three traditional cost components. See G. P. Watkins, *Electrical Rates* (New York, 1921), p. 212. But if this factor were embodied, not only in cost analysis but in the resulting rate differentials, rates would not be uniform throughout a given community and hence would violate a generally accepted tradition.

himself of this solution, since he is the prisoner of his own assumption that "the sum of the parts equals the whole." He is therefore under impelling pressure to "fudge" his cost apportionments by using the category of customer costs as a dumping ground for costs that he cannot plausibly impute to any of his other cost categories.

2. THE ENERGY COSTS

The energy-cost component of this threefold division of total annual costs is supposed to consist of those costs which would vary with changes in consumption of energy, measured in kilowatt-hours, even if the number of customers should remain constant and even if there were no change in maximum load upon the system or subsystem as measured by kilowatts or kilovolt amperes.[9] The most obvious costs of this character are fuel costs, although a small portion even of these costs may be regarded as demand-related on the ground that some fuel is required in order to maintain a "spinning reserve." But other operating costs may also be deemed to vary with output of energy and hence with consumption of energy, including whatever depreciation of the equipment may be regarded as a function of use rather than of obsolescence and aging.

Reduced to costs per kilowatt-hour, the imputed energy costs may be only a fraction of total average costs. It is this relative smallness which is often held to justify a company in conceding very low rates for off-peak or interruptible services, on the ground that these services impose upon the company little or no additional capacity costs.

The treatment of energy costs as a separate cost function is subject to one serious deficiency: namely, in its assumption that the

[9] Estimates of the ratio of energy-related costs to total costs of electric supply (including capital costs) have ranged from ⅓ down to only ¼. Referring to British conditions, Bolton writes: "More accurate costing has shown that, on the average, only one-quarter of the total costs of electricity supply are represented by coal or items proportional to energy, whilst three-quarters are represented by fixed costs or items proportional to power, etc." D. J. Bolton, *Costs and Tariffs in Electricity Supply* (London, 1951), p. 59. But he notes two practical reasons, among others, why this situation does not justify a corresponding dominance of demand charges rather than energy charges in electric rate structures: (a) that the effective power demand imposed upon the system by any given individual is very difficult to determine, and (b) that a pure demand-charge rate would probably lead to a more serious waste of energy than a pure energy rate would lead to a waste of power capacity. The latter reason invokes a "value-of-service" or "demand-elasticity" principle of rate making rather than a cost principle.

The Customer Charge and Problems Of Double Allocation of Costs

By GEORGE J. STERZINGER

After several years of the "great rate debate" attention finally seems to be turning towards a forgotten part of rate design: the customer charge. Utilities, forced by the Public Utility Regulatory Policies Act to justify or do away with declining energy charges, have begun arguing for cost classification and subsequent rate design with increasingly large customer charges. Recently proposed customer charges seem to be consistently in the $6 to $9 range, accompanied by embedded cost-of-service studies supporting even greater charges.

Consumer and environmental groups concerned about rate design reform (rather than using the customer charge as a place to dump costs, as the utilities do) have seen it as a place to shave costs. Concerned primarily with getting a kilowatt-hour or usage charge to reflect incremental or marginal costs more accurately, these groups have attempted to resolve the problem of the resulting excess revenue by proposing that the customer charge be lowered enough to "lose" the surplus. Negative customer charges or lump sum monthly payments from the utility to consumers have been proposed by more imaginative analysts.[1]

Analyses of the proper customer charge have often yielded contradictory results depending upon whether incremental or embedded costs were used. Incremental analyses often, but not always, support low customer charges, while embedded cost analyses often, but not always, support high customer charges.

The importance of incremental price signals and the need to strike a balance between revenue constraints and proper price signals have produced wide agreement that the customer charge is the least "informative" of all parts of a rate design and should be the last place a utility is allowed to collect revenues if incremental costs are found to be useful in designing rates.

Unfortunately, the debate on the proper definition and use of incremental costs remains unresolved, while traditional practices of embedded cost allocation seem to support very high customer charges. Regulators, forced with making a decision, have found some cost basis to be

This article is a critique of the currently most widely used methodology for classifying a portion of electric utility distribution plant as a customer cost. The author argues that this classification, combined with an allocation of the "above minimum" portion on a demand basis, leads to an overallocation of costs to low-use residential customers of the electric system.

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[1] "Customer Charges and the Public Utility Regulatory Policies Act," by Edward F. Renshaw and Perry Renshaw, 104 Public Utilities Fortnightly 17, August 30, 1979, found high customer charges contrary to the intention of PURPA.

preferable to unresolved speculation, and raised the customer charge based on embedded cost-of-service studies.

Since incremental analyses cannot by themselves support a low customer charge, the embedded cost analyses which support high customer charges must also be closely investigated to determine if they meet current objectives of rate design. An examination of these methodologies reveals the following characteristics:

— Almost all of them rely for their justification on the determination of the cost of a minimum distribution system, and the classification of this system as a customer cost.

— Once the classification has been made, it is an inescapable conclusion of the allocated cost-of-service study that calculated customer costs will be substantial.

— However, an examination of the rationale for the classification and the implications of that classification lead equally inescapably to the conclusion that minimum use residential customers will be overcharged by such cost allocation practices.

— The only reasonable remedy for the problem of overcharging is to classify the entire distribution system on a consistent basis, which would be a demand basis.

— Once this is done, traditional cost-of-service studies no longer provide support for high customer charges.

A national survey of utility practices in classification of distribution system costs determine that the great majority used some form of minimum system to classify costs in the relevant Federal Energy Regulatory Commission accounts. (The survey was conducted by Carolina Power and Light Company, Raleigh, North Carolina.) The survey summarized the results of company practices to determine how much, on average, each distribution plant account was classified as demand. The results by FERC account were as follows:

— Account 364 — Poles and fixtures were separated into primary and secondary; the primary portion was split 50-50 between customer and demand costs, the secondary portion was classified 56.5 per cent customer and 43.5 per cent demand.

— Account 365 — Conductors and devices were also separated into primary and secondary; the primary portion was classified 44.3 per cent customer and 55.7 per cent demand, and the secondary portion was classified 46.4 per cent customer and 53.6 per cent demand.

— Account 368 — Line transformers were classified 34 per cent customer and 66 per cent demand.

— Account 369 — Services were classified 70.8 per cent customer and 29.2 per cent demand.

The difficulties with these methodologies only begin with the minimum distribution system. The concept is very difficult to define and consequently susceptible to widely varying interpretations. No single method exists for calculating the cost of this system; nevertheless, a fairly standard approach is to reconstruct the existing distribution system using some type of minimum equipment. Minimum equipment could be of the type employed by the company, currently purchased by the company, currently used in the industry, or currently required by safety code. The cost of this equipment can be either booked or in current prices. Obviously, with this large a menu of definitions to choose from, a utility analyst can calculate costs for these systems over a wide range.

It should be mentioned here that one other method sometimes used to calculate the cost of a minimum system is the "zero-intercept" method whereby regression equations relating cost to various sizes of equipment are derived, and then solved for the cost of zero-sized or "zero-intercept" equipment. The strongest objections to this methodology arise from the limitations on data, the unreliability of the derived equations, and some fundamental problems that arise from making the statistical inference about the cost of the zero-sized equipment.

A typical utility in the sample discussed earlier, faced with the problem of classifying costs in Account 365 —overhead lines, for example, would determine the cost of the minimum equipment needed to replace all existing lines, calculate that cost as a fraction of the total costs of equipment in the account, and use that fraction to classify customer costs. Thus, a utility with 1,000 miles of overhead lines and two types of line costing $1 per foot and $2 per foot would calculate a minimum system cost of roughly $5.28 million ($1 × 5,280 feet per mile × 1,000 miles). This $5.28 million can, of course, be varied if different types of minimum lines are used, or if for other reasons the cost of $1 per foot is changed.

Beyond problems arising from the indeterminate nature of the minimum system, the appropriateness of classifying these costs as customer costs has been long debated. Strictly speaking, customer costs should be limited to those costs which can be shown to vary exclusively with number of customers. Distribution system costs, both as built and hypothetical minimum system, obviously depend to a great extent on geographical considerations — type of terrain and customer density. Several analysts have argued that the nature of cost causation — in this case at least in part due to geography — does not allow the costs to be neatly fit into either demand or customer cost categories; that the costs are simply unallocable. Recent statistical analyses support this notion.[2]

An additional and more severe problem with this methodology arises from the consequences of classifying distribution system costs into both customer and demand portions. Simply put, this practice leads

[2] "The Economics of Electric Distribution System Costs and Investments," by David J. Lessels, 106 PUBLIC UTILITIES FORTNIGHTLY 37, December 4, 1980, found no statistical justification for the classification of distribution costs as customer related.

inevitably to a double allocation and possibly a double collection of these costs from low-use residential customers and a misallocation of costs among customer classes.

To see why this is so, one need only step back for a moment to consider what it is that a cost allocation study attempts to do, and what happens when distribution system costs are split into customer and demand portions and then allocated to individual classes.

An allocation study assigns costs to customers on the basis of usage characteristics; fairness requires that allocated costs follow, as closely as possible, the actual costs of serving customers. Splitting the distribution system into a minimum usage and an above minimum usage portion, and allocating the minimum portion on a customer basis, and the above minimum on a usage basis results in low-use residential customers paying for more of the system than is required to serve them. By splitting the distribution system into two parts, low-use residential consumers are charged twice: once, on a customer basis, for a portion of the system sized to meet their demands; and again on a demand basis for a portion of the system sized to serve demand beyond what would be needed to serve them. The only practical way satisfactorily to assure that low-use customers are charged only once for distribution equipment is to allocate the distribution system costs on a single consistent basis. Of the two considered, customer and demand, it is obvious that only demand can be used to classify and allocate distribution costs on a satisfactory basis.

In order to explain more fully why this method constitutes double charging of low-use customers, we can look more closely at the handling of FERC Accounts 364 and 365 which represent the cost of overhead lines and poles. To illustrate this, suppose the company had only 1,000 miles of overhead lines and 10,000 poles; and in addition it used two types of line — one costing $1 per foot, for 500 miles of overhead, the other costing $2 per foot, for the remainder; and two sizes of pole — 5,000 costing $30 per pole and 5,000 costing $60 per pole. Total cost of this system would be:

a) Line: 500 miles at $1 per foot	$2,640,000	
b) Line: 500 miles at $2 per foot	5,280,000	
Subtotal		$7,920,000
c) Poles: 5,000 poles at $30 per pole	$ 150,000	
d) Poles: 5,000 poles at $60 per pole	300,000	
Subtotal		$ 450,000
Total		$8,370,000

A minimum system in this case would be determined by calculating the cost of the 1,000 miles of overheads if only the minimum-sized line was used, plus the cost of the 10,000 poles if only the minimum-sized pole was used.

Cost of the minimum system is:

a) Line: 1,000 miles at $1 per foot	$5,280,000	
b) Poles: 10,000 poles at $30 per pole	300,000	
Total		$5,580,000

Therefore, the cost of the above minimum (or capacity) system would be the remainder, or $2,780,000.

The minimum system calculated in this fashion could, and actually does, serve a considerable level of usage.

The minimum system is allocated on a customer basis — all customers are charged for an equal share of it. The remainder of the system, the more expensive facilities required to meet loads beyond those handled by minimum-sized equipment, is allocated on some demand basis; noncoincident peak demand is often used. In the calculation of the noncoincident peak demand allocation factors, usage at all levels of the residential and general service customer classes is used to determine allocation factors.

If, for example, the minimum overhead lines, conductors, and poles could supply a demand of two kilowatts per residential customer, that amount of usage would be paid for in the customer charge. In the determination of demand allocation factors, however, each residential customer's demand is calculated and added to determine the portion of the above minimum system costs to be allocated to the residential class and to each customer through the appropriate rates. So a residential customer who has a demand of two kilowatts will have paid for all the distribution costs associated with his load through the customer charge, but will also have his two-kilowatt usage go into the demand allocation factor to allocate distribution costs associated with above minimum usage.

One way to solve the double allocation problem would be to determine, for each piece of minimum equipment, the demand level it would be capable of serving, and then adjusting the demand allocation factors used to allocate the costs of all equipment of that type in order to assure that minimum use customers and the residential class were not charged twice. In many cases this would mean calculating several allocation factors for each FERC distribution account, since more than one type of equipment is used in the account. Even after overcoming all the problems of this approach one is still confronted with the dubious value of charging for equipment on an up-front basis rather than through a per kilowatt-hour charge at a time when conservation is recognized as an important goal of energy policy.

The direct way to assure that problems of overcollection are not built into the methodology used to determine class costs of service is to classify all distribution costs as demand costs. If this methodology is used in embedded cost studies, the studies will produce more equitable estimates of the cost of serving low-use residential customers.

Marcus - Attachment C

RAP | Energy solutions for a changing world

Revenue Regulation and Decoupling:

A Guide to Theory and Application

June 2011

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Contents

Preface

This guide was prepared to assist anyone who needs to understand both the mechanics of a regulatory tool known as *decoupling* and the policy issues associated with its use. This includes public utility commissioners and staff, utility management, advocates, and others with a stake in the regulated energy system.

Many utility-sector stakeholders have recognized the conflicts implicit in traditional regulation that compel a utility to encourage energy consumption by its customers, and they have long sought ways to reconcile the utility business model with contradictory public policy objectives. Simply put, under traditional regulation, utilities make more money when they sell more energy. This concept is at odds with explicit public policy objectives that utility and environmental regulators are charged with achieving, including economic efficiency and environmental protection. This *throughput incentive* problem, as it is called, can be solved with decoupling.

Currently, some form of decoupling has been adopted for at least one electric or natural gas utility in 30 states and is under consideration in another 12 states. As a result, a great number of stakeholders are in need, or are going to be in need, of a basic reference guide on how to design and administer a decoupling mechanism. This guide is for them.

More and more, policymakers and regulators are seeing that the conventional utility business model, based on profits that are tied to increasing sales, may not be in the long-run interest of society. Economic and environmental imperatives demand that we reshape our energy portfolios to make greater use of end-use efficiency, demand response, and distributed, clean resources, and to rely less on polluting central utility supplies. Decoupling is a key component of a broader strategy to better align the utility's incentives with societal interests.

While this guide is somewhat technical at points, we have tried to make it accessible to a broad audience, to make comprehensible the underlying concepts and the implications of different design choices. This guide is accompanied by a spreadsheet that can be used to demonstrate the impacts of decoupling using different pricing structures or, as the jargon has it, *rate designs*.

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1 Natural Resources Defense Council, *Gas and Electric Decoupling in the U.S.*, April 2010.

1. Introduction

This document explains the fundamentals of *revenue regulation*[2], which is a means for setting a level of revenues that a regulated gas or electric utility will be allowed to collect, and its necessary adjunct *decoupling,* which is an adjustable price mechanism that breaks the link between the amount of energy sold and the actual (allowed) revenue collected by the utility. Put another way, *decoupling* is the means by which *revenue regulation* is effected. For this reason, the two terms are typically treated as synonyms in regulatory discourse; and, for simplicity's sake, we treat them likewise here.

Revenue regulation does not change the way in which a utility's allowed revenues (i.e., the "revenue requirement") are calculated. A revenue requirement is based on a company's underlying costs of service, and the means for calculating it relies on long-standing methods that need not be recapitulated in detail here. What is innovative about it, however, is how a defined revenue requirement is combined with decoupling to eliminate sales-related variability in revenues, thereby not only eliminating weather and general economic risks facing the company and its customers, but also removing potentially adverse financial consequences flowing from successful investment in end-use energy efficiency.

We begin by laying out the operational theory that underpins decoupling. We then explain the calculations used to apply a decoupling price adjustment. We close the document with several short sections describing some refinements to basic revenue regulation and decoupling.

To assist the reader, a companion MS-Excel spreadsheet is also available. It contains both the examples shown in this guide, as well as a functioning "decoupling model." It can be downloaded at http://www.raponline.org/docs/RAP_DecouplingModelSpreadsheet_2011_05_17.xlsb

2 Revenue regulation is often called revenue *cap* regulation. However, when combined with decoupling, the effect is to simply regulate revenue – i.e., there is a corresponding *floor* on revenues in addition to a *cap*.

2. Context for Decoupling

Decoupling is a tool intended to break the link between how much energy a utility delivers and the revenues it collects. Decoupling is used primarily to eliminate incentives that utilities have to increase profits by increasing sales, and the corresponding disincentives that they have to avoid reductions in sales. It is most often considered by regulators, utilities, and energy-sector stakeholders in the context of introducing or expanding energy efficiency efforts; but it should also be noted that, on economic efficiency grounds, it has appeal even in the absence of programmatic energy efficiency.

There are a limited number of things over which utility management has control. Among these are operating costs (including labor) and service quality. Utility management can also influence usage per customer (through promotional programs or conservation programs). Managers have very limited ability to affect customer growth, fuel costs, and weather. Decoupling typically removes the influence on revenues (and profits) of such factors and, by eliminating sales volumes as a factor in profitability, removes any incentive to encourage consumers to increase consumption. This focuses management efforts on cost-control to enhance profits.

In the longer run, this effort constrains future rates and benefits consumers. It also means that energy conservation programs (which reduce customer usage) do not adversely affect profits. A performance incentive system and a customer-service quality mechanism can overlay decoupling to further promote public interest outcomes.

Although it is often viewed as a significant deviation from traditional regulatory practice, decoupling is, in fact, only a slight modification. The two approaches affect behavior in critically different ways, yet the mathematical differences between them are fairly straightforward. Still, it goes without saying that care must be taken in designing and implementing a decoupling regime, and the regulatory process should strive to yield for both utilities and consumers a transparent and fair result.

While traditional regulation gives the utility an incentive to preserve and, better yet, increase sales volumes, it also makes consumer advocates focus on price – after all, that is the ultimate result of traditional regulation. Because decoupling allows prices to change between rate cases, consumer advocates can move the focus of their effort from prices to all cost drivers, including sales volumes – focusing on bills rather than prices.

3. How Traditional Regulation Works

In virtually all contexts, public utilities (including both investor-owned and consumer-owned utilities) have a common fundamental financial structure and a common framework for setting prices.[3] This common framework is what we call the utility's overall *revenue requirement.* Conceptually, the revenue requirement for a utility is the aggregate of all of the operating and other costs incurred to provide service to the public. This includes operating expenses like fuel, labor, and maintenance. It also includes the cost of capital invested to provide service, including both interest on debt and a "fair" return to equity investors. In addition, it includes a depreciation allowance, which represents repayment to banks and investors of their original loans and investments.

In order to determine what price a utility will be allowed to charge, regulators must first compute the total cost of service, that is, the revenue requirement. Regulators then compute the price (or rate) necessary to collect that amount, based on assumed sales levels. In most cases, the regulator relies on data for a specific period, referred to here as the *test period,* and performs some basic calculations.

Here are the two basic formulae used in traditional regulation:

Formula 1: **Revenue Requirement = (Expenses + Return + Taxes)** TEST PERIOD
Formula 2: **Rate = Revenue Requirement ÷ Units Sold** TEST PERIOD

The rate is normally calculated on a different basis for each customer class, but the principle is the same – the regulator divides the revenue requirement among the customer classes, then designs rates for each class to recover each class's revenue requirement. Table 1 is an example of this calculation, under the simplifying assumption that the entire revenue requirement is collected through a kWh charge.

3 Conditions vary widely from country to country or region to region, and utilities face a number of local and unique challenges. However, for our purposes, we will assume that there is a fundamental financial need for revenues to equal costs – including any externally imposed requirements to fund or secure other expense items (such as required returns to investors, debt coverage ratios in debt covenants, or subsidies to other operations, as is often the case with municipal- or state-run utilities). In this sense, virtually all utilities can be viewed as being quite similar.

3.1 Revenue Requirement

A utility's revenue requirement is the amount of revenue a utility will actually collect, only if it experiences the sales volumes assumed for purposes of price-setting. Furthermore, only if the utility incurs exactly the expenses and operates under precisely the financial conditions that were assumed in the rate case will it earn the rate of return on its rate base (i.e., the allowed investment in facilities providing utility service) that the regulators determined was appropriate. While much of the rate-setting process is meticulous and often arcane, the fundamentals do not change: in theory a utility's revenue requirement should be sufficient to cover its cost of service — no more and no less.

Table 1

Traditional Regulation Example: **Revenue Requirement Calculation**	
Expenses	**100,000,000**
Net Equity Investment	**100,000,000**
Allowed Rate of Return	**10.00%**
Allowed Return	**$10,000,000**
Taxes (35% tax rate)	**$5,384,615**
Total Return & Taxes	**$15,384,615**
Total Revenue Requirement	**$115,384,615**
Price Calculation	
Revenue Requirement	**$115,384,615**
Test Year Sales (kWh)	**1,000,000,000**
Rate Case Price ($/kWh)	**$0.1154**

3.1.1 Expenses

For purposes of decoupling, expenses come in two varieties: production costs and non-production costs.[4]

3.1.1.1 Production Costs

Production costs are a subset of total power supply costs, and are composed principally of fuel and purchased power expenses with a bit of variable operation and maintenance (O&M) and transmission expenses paid to others included. Production costs as we use the term here are those that vary more or less directly with energy consumption in the short run. The mechanisms approved by regulators generally refer to very specific accounts defined in the utility accounting manuals, including "fuel," "purchased power," and "transmission by others."

4 A utility's expenses are often characterized as "fixed" or "variable". However, for purposes of resource planning and other long-run views, all costs are variable and there is no such thing as a fixed cost. Even on the time scale between rate cases, some non-production costs that are often viewed as fixed (e.g., metering and billing) will, in fact, vary directly with the number of customers served. When designing a decoupling mechanism, it is more appropriate to differentiate between "production" and "non-production," since one purpose of the mechanism is to isolate the costs over which the utility actually has control in the short run (i.e., the period between rate cases).

Production costs for most electric utilities are typically recovered through a flow-through account, with a reconciliation process that fully recovers production costs, or an approximation thereof.[5] This is usually accomplished through a separate fuel and purchased-power rate (fuel adjustment clause, or FAC) on the customer's bill. This may be an "adder" that recovers total production costs, or it may be an up-or-down adjustment that recovers deviations in production costs from the level incorporated in base rates.

In the absence of decoupling, a fully reconciled FAC creates a situation in which any increase in sales results in an increase in profits, and any decrease in sales results in a decrease in profits. This is because even if very high-cost power is used to serve incremental sales, and if 100% of this cost flows through the FAC, the utility receives a "net" addition to income equal to the base rate (retail rate less production costs) for every incremental kilowatt-hour sold.[6] An FAC is therefore a negative influence on the utility's willingness to embrace energy efficiency programs and other actions that reduce utility sales. Decoupling is an important adjunct to an FAC to remove the disincentive that the FAC creates for the utility to pursue societal cost-effectiveness.[7]

Because they vary with production and because they are separately treated already, production costs are not usually included in a decoupling mechanism. If a utility is allowed to include the investment-related portion of costs for purchased power contracts (i.e., it buys power to serve load growth from an independent power producer, and pays a per-kWh rate for the power received), it may be necessary to address this in the structure of the FAC to ensure that double recovery does not occur. This can also be addressed by using a comprehensive power cost adjustment that includes all power supply costs, not just fuel and purchased power. Unless otherwise noted, we assume that production costs are not included in the decoupling mechanism.

5 Many commissions use incentive mechanisms in their fuel and purchased-power mechanisms, to provide utilities with a profit motive to minimize fuel and purchased-power costs and to maximize net off-system sales revenues. For our purposes, these are deemed to fully recover production costs. Some regulators include both fixed and variable power supply costs in their power supply cost recovery mechanism, in which case all of those would be classified as "production" costs and deemed to be fully recovered through the power supply mechanism.

6 See *Profits and Progress Through Least Cost Planning,* NARUC, page 4, at: http://www.raponline.org/Pubs/General/Pandplcp.pdf

7 If a utility does not have an FAC at all, or acquires power from independent power producers on an ongoing basis to meet load growth, the framework for decoupling may need to be slightly different. In those circumstances, revenues from the sale of surplus power or avoided purchased power expense resulting from sales reductions flows to the utility, not to the consumers, through the FAC. In this situation, the definition of "production costs" may need to include both power supply investment-related costs and production-related operating expenses for decoupling to produce equitable results for consumers and investors.

3.1.1.2 Non-Production Costs

Non-production costs include all those that are not production costs — in essence, everything that is related to the delivery of electricity (transmission, distribution, and retail services) to end users. This normally includes all non-production related O&M expenses, including depreciation and interest on debt. In many cases, the base rates also include the debt and equity service (i.e., the interest, return, and depreciation) on power supply investments, in which case the form of the FAC becomes important.

Statistically, a utility's non-production costs do not vary much with consumption in the short run, but are more affected by changes in the numbers of customers served, inflation, productivity, and other factors.[8] Of course, a utility with a large capital expenditure program, such as the deployment of smart grid technologies or significant rebuilds of aging systems, will experience a surge in costs that is unrelated to customer growth. Decoupling does not address this issue, which is better handled in the context of a rate case or infrastructure tracking mechanism.

Non-production costs are usually recovered through a combination of a customer charge,[9] plus one or more volumetric (per kWh, per kW) rates. A utility may face the risk of not recovering some non-production costs if sales decline. Put another way, many of the costs do not vary with sales, so each dollar decline in sales flows straight to — and adversely affects — the bottom line.

3.1.2 Return

For our purposes, the utility's "return" is the same as its net, after-tax profit, or net income for common stock.[10] When computing a revenue requirement for a rate case, this line item is derived by multiplying the utility's net equity investment by its "allowed" rate of return on common equity. We have simplified this return in the illustration, but will address it in more detail in Section 10, *Earnings Volatility Risks and Impacts on the Cost of Capital.*

In a rate case, the return is a static expected value. In between rate cases,

8 Eto, Joseph, Steven Stoft, and Timothy Belden, *The Theory and Practice of Decoupling,* Lawrence Berkeley National Laboratory, January 1994. URL: http://eetd.lbl.gov/ea/EMS/reports/34555.pdf

9 In place of a customer charge, one may also find other monthly fixed charges, such as minimum purchase amounts, access fees, connection fees, or meter fees. For our purposes, these are all the same because they are not based on energy consumption, but, instead, are a function of the number of customers.

10 Regulatory commissions often calculate an "operating income" figure in the process of setting rates; this does not take account of the tax effects on the debt and equity components of the utility capital structure. Net income includes these effects.

11 Shirley, W., J. Lazar, and F. Weston, *Revenue Decoupling: Standards and Criteria, A Report to the Minnesota Public Utilities Commission,* Regulatory Assistance Project, 30 June 2008, Appendix B, p. 36.

realized returns are a function of actual revenues, actual investments, and actual expenses, all of which change between rate cases in response to many factors, including sales volumes, inflation, productivity, and many others.

As a share of revenues in a rate case revenue requirement calculation, the return on equity to shareholders may be as small as 5%-10%. As a result, small percentage changes in total non-production revenues (all of which largely affect return and taxes) can generate large percentage changes in net profits.[11]

3.1.3 Taxes

In a rate case, the amount of taxes a utility would pay on its allowed return is added to the revenue requirement.

In between rate cases, taxes buffer the impact on the utility's shareholders of any deviations of realized returns from expected returns. When realized returns rise, some portion is lost to taxes, so shareholders do not garner gains one-for-one with changes in net revenues. Conversely, if revenues fall, so do taxes. As a result, investors do not suffer the entire loss. If the tax rate is 33%, then one third of every increase or decrease in pre-tax profits will be absorbed by taxes.

From a customer perspective, there is no buffering effect from taxes. To the contrary, customers pay all additional revenues and enjoy all savings, dollar for dollar.

3.1.4 Between Rate Cases

With traditional regulation, while the determination of the revenue requirement *at the time of the rate case decision* is meticulous, the utility will almost certainly *never* collect precisely the allowed amount of revenue, experience the associated assumed levels of expenses or unit sales, or achieve the expected profits. The revenue requirement is only used as input to the price determination. Once prices are set, *realized* revenues and profits will be a function of *actual sales and expenses* and will have only a rough relationship with the rate case allowed revenues or returns.

Traditional regulation fixes the price between rate cases and lets revenues float up or down with actual sales.

Put another way, traditional regulation fixes the price between rate cases and lets revenues float up or down with actual sales. At this point, the rate case formulae no longer hold sway. Instead, two different mathematical realities operate:

Formula 3: **Revenues** $_{\text{ACTUAL}}$ **= Units Sold Actual X Price**

Formula 4: **Profit** $_{\text{ACTUAL}}$ **= (Revenues – Expenses – Taxes)** $_{\text{ACTUAL}}$**l**

These two formulae reveal the methods by which the utility can increase its profits. One approach is to reduce expenses. Providing a heightened

incentive to operate efficiently is sound. However, there is a floor below which expenses simply cannot be reduced without adversely affecting the level of service, and to ensure that utilities cut fat, but not bone, some regulators have established service quality indices that penalize utilities that achieve lower-than-expected customer service quality. The easier approach is to increase the Units Sold, as this will increase revenues and therefore profits.[12] This is the heart of the throughput incentive that utilities traditionally face – and this is where decoupling comes in.

3.2 How Decoupling Works

There are a variety of different approaches to decoupling, all of which share a common goal of ensuring the recovery of a defined amount of revenue, independent of changes in sales volumes during that period. Some are computed on a revenue-per-customer basis, while others use an attrition adjustment (typically annual) to set the allowed revenue. Some operate on an annual accrual basis, while others operate on a current basis in each billing cycle. Table 2 categorizes these and provides an example of each approach; a greater discussion of these approaches is contained in the appendix.

Table 2

Decoupling Methodology	Key Elements	Example of Application
Accrual Revenue Per Customer	Allowed revenue computed on an RPC basis; one rate adjustment per year	Utah, Questar
Current Revenue Per Customer	Allowed revenue computed on an RPC basis; rates adjusted each billing cycle to avoid deferrals	Oregon, Northwest Natural Gas Company; DC: Pepco
Accrual Attrition	Allowed revenue determined in periodic general rate cases; changes to this based on specified factors determined in annual attrition reviews; rates adjusted once a year	California, PG&E and SCE Hawaii, Hawaiian Electric
Distribution-Only	Only distribution costs included in the mechanism; all power costs (fixed and variable) recovered outside the decoupling mechanism	Massachusetts, NGrid Maryland, BG&E Washington (PSE, 1990-95)

12 This is because, as noted earlier, the utility faces virtually no changes in its non-production costs as its sales change. This means that marginal increases in sales will have a large and positive impact on the bottom line, just as marginal reductions in sales will have the opposite effect.

3.2.1 In the Rate Case (It's the same)

With decoupling there is no change in the rate case methodology, except perhaps for the migration of some cost items into or out of the production cost recovery mechanism.[13] Initial prices are still set by the regulator, based on a computed revenue requirement.

Formula 1: **Revenue Requirement = (Expenses + Return + Taxes)** $_{\text{Test Period}}$
Formula 5: **Price** $_{\text{End of Rate Case}}$ **= Revenue Requirement ÷ Units Sold** $_{\text{Test Period}}$

3.2.2 Between Rate Cases (It's different)

With decoupling, the price computed in the rate case is only relevant as a reference or beginning point. In fact, the rate case prices may never actually be charged to customers. Instead, under "current" decoupling (described below), prices can be adjusted immediately, based on actual sales levels, to keep revenues at their allowed level. Rather than holding prices constant between rate cases as traditional regulation would do, decoupling adjusts prices periodically, even as frequently as each billing cycle, to reflect differences between units sold $_{\text{Test Period}}$ and units sold $_{\text{Actual}}$, as necessary to collect revenues $_{\text{Allowed}}$. This is accomplished by applying the following formulae:

There are two distinct components of decoupling which are embedded in the decoupling formulae: determination of the utility's allowed revenues and determination of the prices necessary to collect those allowed revenues.

Formula 6: **Price** $_{\text{Post Rate Case}}$ **= Revenues** $_{\text{Allowed}}$ **÷ Units Sold** $_{\text{Actual}}$
Formula 7: **Revenues** $_{\text{Actual}}$ **= Revenues** $_{\text{Allowed}}$
Formula 4: **Profits** $_{\text{Actual}}$ **= (Revenues – Expenses – Taxes)** $_{\text{Actual}}$

Table 3 gives an example of the calculations.

13 Examples of costs that are sometimes recovered on an actual cost basis include nuclear decommissioning (which rises according to a sinking fund schedule), energy conservation program expenses, and infrastructure trackers for non-revenue-generating refurbishments. Where a utility does not have an FAC or purchases power from independent power producers to meet load growth, it may be necessary to include all power supply costs, fixed and variable, in the definition of "production costs."

There are two distinct actions embedded in the decoupling formulae: determination of the utility's *allowed* revenues and determination of the *prices* necessary to collect those allowed revenues. The former can involve a variety of methods, ranging from simply setting allowed revenues at the amount found in the last rate case to varying revenues over time to reflect non-sales-related influences on costs and revenues, as discussed in Section 5, *Revenue Functions.* The latter is merely the calculation which sets the prices that, given sales levels (i.e., billing determinants), will generate the allowed revenue.

Table 3

Decoupling Example: **Revenue Requirement Calculation**	
Expenses	**$100,000,000**
Net Equity Investment	**$100,000,000**
Allowed Rate of Return	**10.00%**
Allowed Return	**$10,000,000**
Taxes (35% tax rate)	**$15,384,615**
Total Revenue Requirement	**$115,384,615**
Price Calculation	
Revenue Requirement	**$115,384,615**
Actual Sales (kWh)	**990,000,000**
Decoupling Price ($/kWh)	**$0.1166**
Decoupling Adjustment ($/kWh)	**$0.0012**

Put another way, while traditional regulation sets prices, then lets revenues float up or down with consumption, decoupling sets revenues, then lets prices float down or up with consumption. This price recalculation is done repeatedly – either with each billing cycle or on some other periodic basis (e.g., annual), through the use of a deferral balancing and reconciliation account.[14]

While traditional regulation sets prices, then lets revenues float up or down with consumption, decoupling sets revenues, then lets prices float down or up with consumption.

There are two separate elements in play in the price-setting component of decoupling. The first is that prices are allowed to change between rates, based on deviations in sales from the test period assumptions. The second is the frequency of those changes. We discuss the frequency idea in greater detail in Section 8, *Application of Decoupling: Current vs. Accrual Methods.*

14 There are, however, good reasons to seek to limit the magnitude of deviations from the reference price. For example, many decoupling mechanisms allow a maximum 3% change in prices in any year, deferring larger variations for future treatment by the regulator. Significant variability in price may threaten public acceptance of decoupling and the broader policy objectives it serves. Policymakers should be careful to design decoupling regimes with this consideration in mind.

4 Full, Partial, and Limited Decoupling

We use a specialized vocabulary to differentiate various approaches to decoupling.

4.1 Full Decoupling

Full decoupling can be likened to the setting of a budget.

Decoupling in its essential, fullest form insulates a utility's revenue collections from any deviation of actual sales from expected sales. The cause of the deviation — e.g., increased investment in energy efficiency, weather variations, changes in economic activity — does not matter. Any and all deviations will result in an adjustment ("true-up") of collected utility revenues with allowed revenues. The focus here is delivering revenue to match the revenue requirement established in the last rate case.

Full decoupling can be likened to the setting of a budget. Through currently used rate-case methods, a utility's revenue requirement — i.e., the total revenues it will need in a period (typically, a year) to provide safe, adequate, and reliable service — is determined. The utility then knows exactly how much money it will be allowed to collect, no more, no less. Its profitability will be determined by how well it operates within that budget. Actual sales levels will not, however, have any impact on the budget.[15]

The most common form of full decoupling is revenue-per-customer decoupling, which is more fully explained with other forms of decoupling in the next section. The California approach, wherein a revenue requirement is fixed in a rate case and incremental (or decremental) adjustments to it are determined in periodic "attrition" cases, is also a form of full decoupling. Tracking mechanisms, designed to generate a set amount of revenue to

15 This is the simplest form of full decoupling. As described in the next section, most decoupling mechanisms actually allow for revenues to vary as factors other than sales vary. The reasoning is that, though in the long run utility costs are a function of demand for the service they provide, in the short run (i.e., the rate-case horizon) costs vary more closely with other causes, primarily changes in the numbers of customers.

cover specific costs (independently of base rates and the underlying cost of service) are not incompatible with full decoupling. They would be reflected in separate tariff surcharges or surcredits.

Full decoupling renders a utility indifferent to changes in sales, regardless of cause. It eliminates the "throughput" incentive. The utility's revenues are no longer a function of sales, and its profits cannot be harmed or enhanced by changes in sales. Only changes in expenses will then affect profits.

Decoupling eliminates a strong disincentive to invest in energy efficiency. By itself, however, decoupling does not provide the utility with a positive incentive to invest in energy efficiency or other customer-sited resources, but it does remove the utility's natural antagonism to such resources due to their adverse impact on short-run profits. Assuming that management has a limited ability to influence costs and behavior, this allows concentration of that effort on cost reductions, rather than sales enhancements.

4.2 Partial Decoupling

Partial decoupling insulates only a portion of the utility's revenue collections from deviations of actual from expected sales. Any variation in sales results in a partial true-up of utility revenues (e.g., 50%, or 90%, of the revenue shortfall is recovered).

One creative application of partial decoupling was the combination conservation incentive/decoupling mechanism for Avista Utilities in Washington. The utility was allowed to recover a percentage of its lost distribution margins from sales declines in proportion to its percentage achievement of a Commission-approved conservation target. If it achieved the full conservation target, it was allowed to recover all of its lost margins, but if it fell short, it was allowed only partial recovery.[16] This proved a powerful incentive to fully achieve the conservation goal.

4.3 Limited Decoupling

Under limited decoupling only specified causes of variations in sales result in decoupling adjustments. For example:

- Only variations due to weather are subject to the true-up (i.e., actual year revenues [sales] are adjusted for their deviation from weather-normalized revenues). This is simply a weather normalization adjustment clause. Other impacts on sales would be allowed to affect revenue collections. Successful implementation of energy efficiency programs would, in this context, result in reductions in sales and

16 Washington Utilities and Transportation Commission, Docket UG-060518, 2007. The recovery was capped at 90%.

revenues from which the utility would not be insulated — that is, all else being equal, energy efficiency would adversely affect the company's bottom line. Weather-only adjustment mechanisms have been implemented for several natural gas distribution companies.

- Lost-margin mechanisms, which recover only the lost distribution margin related to utility-operated energy efficiency programs, have been implemented for several utilities. These generally provide a removal of the disincentive for utilities to operate efficiency programs, but may create perverse incentives for utilities to discourage customer-initiated efficiency measures or improvements in codes and standards that cause sales attrition, because these are not compensated.
- Reduced usage by existing customers may be "decoupled," whereas new customers are not included in the mechanism, on the theory that the utility is more able to influence, through utility programs, the usage of existing customers who were a part of the rate-case determination of a test year revenue requirement.
- Variations due to some or all other factors (e.g., economy, end-use efficiency) except weather are included in the true-up. In this instance, the utility and, necessarily, the customers still bear the revenue risks associated with changes in weather. And, lastly,
- Some combination of the above.

Limited decoupling requires the application of more complex mathematical calculations than either full or partial decoupling, and these calculations depend in part on data whose reliability is sometimes vigorously debated. But more important than this is the fundamental question that the choice of approaches to decoupling asks: how are risks borne by utilities and consumers under decoupling, as opposed to traditional regulation? What value derives from removing sales as a motivator for utility management? What value derives from creating a revenue function that more accurately collects revenue to match actual costs over time? What are the expected benefits of decoupling, and what, if anything, will society be giving up when it replaces traditional price-based regulation with revenue-based regulation?

Limited decoupling does not fully eliminate the throughput incentive. The utility's revenues (and profits, therefore) are still to some degree dependent on sales. So long as it retains a measure of sales risk, the achievement of public policy goals in end-use efficiency and customer-sited resources, environmental protection, and the least-cost provision of service will be inhibited.[17]

17 "Limited decoupling" is synonymous with "net lost revenue adjustments." "Net lost revenue adjustments" is the term of art that describes earlier methods of compensating a utility for the revenue to cover non-production costs that it would have collected had specified sales-reducing events or actions (e.g., cooler-than-expected summer weather, or government-mandated end-use energy investments) not occurred.

5 Revenue Functions

One of the collateral benefits of decoupling is the potential for reducing the frequency of rate cases. In its simplest form, a decoupling mechanism maintains revenues at a constant level between rate cases. However, this would inevitably put increasing downward pressure on earnings due to general net growth in the utility's cost structure as new customers are added and operating expenses are driven by inflation, to the extent these are not offset by depreciation, productivity gains, and, in certain cases, cost decreases.

To avoid this problem, the allowed (or "target") revenue a utility can collect in any post-rate-case period can be adjusted relative to the rate-case revenue requirement. Most decoupling mechanisms currently in effect make use of one or more revenue functions to set allowed revenues between rate cases, and we describe the four standard ones here: (1) adjusting for inflation and productivity; (2) accounting for changes in numbers of customers; (3) dealing with attrition in separate cases; and (4) the application of a "K" factor to modify revenue levels over time. There may be others that are, in particular circumstances, also appropriate.

5.1 Inflation Minus Productivity

Before development of the current array of decoupling options, a number of jurisdictions used what has been called "performance-based regulation" (PBR) — relying on a price-cap methodology, instead of decoupling's revenue-based approach. These plans, first developed for telecommunications providers, often included a price adjuster under which the affected (usually non-production) costs of the utility were assumed to grow through the net effects of inflation (a positive value) and increased productivity (a negative

18 Under normal economic conditions, inflation will be a positive value and productivity a negative value, but there can be circumstances that violate this presumption — an extended period of deflation, for instance. In fact, when Great Britain's state-owned electric transmission and distribution companies were privatized in the late 1980s, their prices were regulated under PBR formulas that included positive productivity adjustments. "[Positive] X (that is, an apparent allowance for annual rates of productivity decreases of X percent) factors were chosen in order to provide the industry with sufficient future cash flow in part to meet projected future investment needs and also to increase the attractiveness of the companies to the investment

value).[18] Prices were allowed to grow at the rate of inflation, less productivity, in an effort to track these expected changes in the utility's cost of service. In some cases, other factors (often called "Z" factors) were added to the formulae to represent other explicit or implicit cost drivers. For example, if a union contract had a known inflationary factor, this might be used in lieu of a general inflation index, but only for union labor expenses.

This adjustment is being used in revenue-decoupling regulation, too, to determine a revenue path between rate cases. Rather than applying this adjustment to prices, it is applied to the allowed revenue between rates cases.[19] This approach is used in California, with annual "attrition" cases that consider other changes since the last general rate case, then add (or subtract) these from the revenue requirement determined in the rate case.

With the inflation and productivity factors in hand, the allowed revenue amount can be adjusted periodically. In practice, this adjustment has usually been done through an annual administrative filing and review. In theory, however, there is no practical reason these adjustments could not be made on a current basis, perhaps with each billing cycle.[20] In application, the net growth in revenue requirement is usually spread evenly across all customers and all customer classes.

The inflation-minus-productivity approach does not remove all uncertainty from price changes, because the actual inflation rate used to derive allowed revenues (and, therefore, reference prices) will vary over time.

community during their upcoming public auction. The initial regulatory timeframe was set at the fiscal year 1990/1995 time period." See http://actrav.itcilo.org/actrav-english/telearn/global/ilo/frame/elect2.htm. (Note that this adjustment is actually referred to as "negative productivity," since it indicates a reduction, rather than an increase, in productivity. Mathematically, it's denoted as the negative of a negative, and so for simplicity's sake we've described it as positive here.)

19 Under this approach, a government-published (or other accepted "third party" source), broad-based inflation index is used. The productivity factor, which serves to offset inflation, is also an administratively determined or, in some cases, a stakeholder agreed-upon value. It should not, however, be calculated as a function of the particular company's own productivity achievements. Doing so would reward a poorly performing company with an overall revenue adjustment (inflation-minus-productivity factor) that is too high (and which does not give it strong enough incentives to control costs) and would punish a highly performing company with a factor that reduces the gains it would otherwise achieve, in effect holding it to a more stringent standard than other companies face.

20 See also *Current vs. Accrual Methods*, below, for more on the implications of using *accrual* methodologies for decoupling versus using a *current* system. It goes without saying, of course, that price changes of this sort can only be effected through a simple, regular ministerial process, if the adjustment factors on which they are based are transparent, unambiguous, and factual in nature (e.g., customer count). If, however, the adjustment is driven by changes that are within management's discretionary — say, capital budget — then a more detailed review may be required to assure that prudent decisions are underlying the revenue adjustments.

5.2 Revenue-per-Customer (RPC) Decoupling

As noted earlier, analysis has shown that, in the time between rate cases, changes in a utility's underlying costs vary more directly with changes in the number of customers served than they do with other factors such as sales, although the correlation on a total expense basis to any of these is relatively weak. When examining only non-production costs, however, the correlations are much stronger, especially for the number of customers.

In 2001, we previously studied the relationships between drivers such as system peak, total energy, and number of customers to investments in distribution facilities.[21]

RAP prepared studies for correlations between investments in transformers and substations versus lines and feeders as they relate to growth in customers served, system peak, and total energy sales. The data indicate that customer count is somewhat more closely correlated with growth in non-production costs, stronger than either growth in system peak or growth in energy sales. These data support using the number of customers served as the driver for computing allowed revenues between rate cases, particularly in areas where customer growth has been relatively stable and is expected to continue. The revenue-per-customer, or RPC method, may not be appropriate in areas with stagnant economies or volatile spurts of growth, or where new customers are significantly different in usage patterns than existing customers, but in these situations, the attrition method may still work well.

The data indicate that customer growth is closely correlated to growth of non-production costs.

The RPC value is derived through an added "last" step in the rate case determination. It is computed by taking the test period revenues associated with each volumetric price charged, and dividing that value by the end-of-test period number of customers who are charged that volumetric price. This calculation must be made for each rate class, for each volumetric price, and for each applicable billing period (most likely a billing cycle):

Formula 8: **Revenue per Customer** $_{\text{Test Period}}$ **=**
Revenue Requirement $_{\text{Test Period}}$ **÷ No. of Customers** $_{\text{Test Period}}$

With this revenue-per-customer number, allowed revenues can be adjusted periodically to reflect changes in numbers of customers. In any

21 See *Distributed Resource Policy Series: Distribution System Cost Methodologies for Distributed Generation* available at http://www.raponline.org/docs/RAP_Shirley_DistributionCostMethodologiesforDistributedGeneration_2001_09.pdf and the accompanying Appendices at: http://www.raponline.org/docs/RAP_Shirley_DistributionCostMethodologiesforDistributedGenerationAppx_2001_09.pdf

Table 4

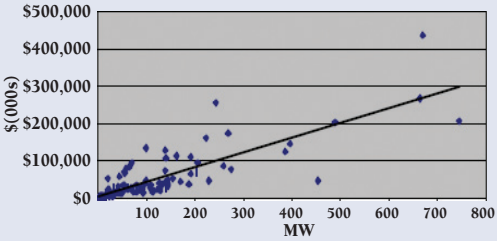
Lines & Feeders

Growth in Lines & Feeders Investment vs. Growth in System Peak

(Five Year Adjusted Average, 1995-1999)

Statistical Summary

Standard Deviation . . $2,129,439
Average $608,215
Correlation 0.80

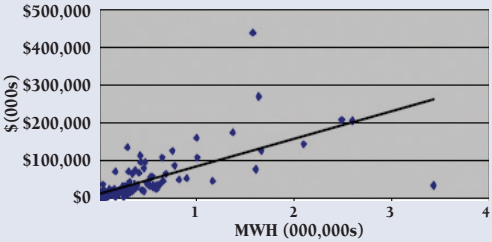


Growth in Lines & Feeders Plant Investment vs. Growth in System Energy

(Five Year Average, 1995-1999/Excludes Negative Growth)

Statistical Summary

Standard Deviation $606
Average $74
Correlation 0.53

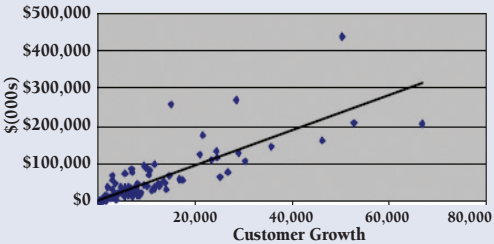


Growth in Lines & Feeders Plant Investment vs. Growth in Customers

(Five Year Average, 1995-1999/Excludes Negative Growth)

Statistical Summary

Standard Deviation $13,191
Average $4,551
Correlation 0.82



post-rate-case period, the allowed revenues for energy and demand charges are calculated by multiplying the actual number of customers served by the RPC value for the corresponding billing period. The decoupling adjustment is then calculated in the manner detailed in the earlier sections.

Formula 9: **Revenues** $_{\text{ALLOWED}}$ **= Revenue per Customer** $_{\text{TEST PERIOD}}$
X No. of Customers $_{\text{ACTUAL}}$

Formula 10: **Price** $_{\text{ACTUAL}}$ **= Revenues** $_{\text{ALLOWED}}$ **÷ Units Sold** $_{\text{ACTUAL}}$

The table below demonstrates the RPC calculations for three billing periods for a sample small commercial rate class. In this example, the billing periods are assumed to be monthly. Note that the revenues per customer are different in each month, because of the seasonality of consumption in the test period.[22]

By calculating the energy and demand revenues per customer for each

Table 5

Deriving the Revenue per Customer Values

Small Commercial Class Example
Test Period Values

Billing Period	**1**	**2**	**3**
Number of Test Period Customers	142,591	142,769	142,947
Customer Charge	$25.00	$25.00	$25.00
Total Customer Charge Revenues	$3,564,775	$3,569,225	$3,573,675
Energy Revenue per Customer			
Energy Sales (kWh)	181,238,883	189,304,436	170,240,013
Rate Case Price	$0.165	$0.165	$0.165
Total Energy Sales Revenues	$29,904,416	$31,235,232	$28,089,602
Energy Revenue per Customer	$209.72	$218.78	$196.50
Demand Revenue per Customer			
Demand Sales (kW)	1,189,355	1,165,396	1,148,975
Rate Case Price	$4.4600	$4.4600	$4.4600
Total Demand Sales Revenues	$5,304,523	$5,197,667	$5,124,429
Demand Revenue per Customer	$37.20	$36.41	$35.85

22 Most utilities typically have 22 or 23 billing cycles per month. For simplicity, we have assumed here that all customers in a month are billed in the same billing cycle (one per month). In the future, with new "smart" metering and communication platforms, a single billing cycle per month, for all customers, may be possible.

billing period, normal seasonal variations in consumption are automatically captured. This causes revenue collection to match the underlying seasonal consumption patterns of the customers.

Some decoupling schemes exclude very large industrial customers. Because the rates for these customers are often determined by contractual requirements and specified payments designed to cover utility non-production costs, there may be little or no utility throughput incentive opportunity relating to these customers anyway. Also, in many utilities, this class of customers may consist of only a small number of large and unique (in load-shape terms) customers, so that a "class" approach is not apt.

In cases in which new customers (that is, those who joined the system during the term of the decoupling plan) have significantly different consumption patterns (and, therefore, revenue contributions to the utility) than existing customers, regulators may want to modify the decoupling formula to account for the difference. This can be accomplished by using different RPC values for new customers and existing customers. The nature of this issue and methodologies for addressing it are discussed in Section 6, *Application of RPC Decoupling: New vs. Existing Customers.*

5.3 Attrition Adjustment Decoupling

Some jurisdictions take a different approach to decoupling. They set base rates in a periodic major rate case, then conduct annual abbreviated reviews to determine whether there are particular changes in costs that merit a change in rates. In such instances, the regulators adjust rate base and operating expenses only for known and measurable changes to utility costs and revenues since the rate case, and adjust for them through a small increment or decrement to the base rates (called "attrition adjustments"). The regulators normally do not consider more controversial issues such as new power plant additions or the creation of new classes of customers, which are reserved for general rate cases.

In attrition decoupling, the utility's allowed revenue requirement is the amount allowed in the first year after the rate case, plus the addition (or reduction) that results from the attrition review. Every few years, a new general rate case is convened to re-establish a cost-based revenue requirement considering all factors.

5.4 K Factor

The K factor is an adjustment used to increase or decrease overall growth in revenues between rate cases.

In its simplest application, the K factor can be used in lieu of either the

inflation-minus-productivity method or the RPC method; it could be, for example, a specified percentage per year. Although one could vary the K factor itself over time, in this context the most likely application would simply set an annual between-rate-case growth rate for revenues, resulting in a steady change (probably an increase) in year-to-year allowed revenues for each period between rate cases. Such an approach has a high degree of certainty, but runs the risk of being disassociated from, and therefore out of sync with, measurable drivers of a utility's cost of service. All of the data used in a rate case change over time, and the elements making up the K factor are no different. The K factor therefore may become obsolete within a few years, providing another reason why periodic general rate cases should be required by regulators under decoupling (and, arguably, under traditional regulation as well).

A "successful" revenue function would be one that keeps the utility's actual revenue collection as close as possible to its actual cost of service throughout the period between rate cases.

An alternative approach is to use the K factor as an adjustment to the RPC allowed revenue determination. Here, the K factor growth rate (positive or negative) would be applied to the RPC values, rather than to the allowed revenue value itself. This approach would be useful when an additional revenue requirement is anticipated due to identifiable increases in revenues from capital expenditures or operating expenses, or because of some underlying trend in the RPC values. An example would be a utility with a distribution system upgrade program driven by reliability concerns, where the investment is not generating new revenue. It may also be used as an incentive for the utility to make specific productivity gains, in which case the K factor would be a negative value causing revenues to be slightly lower than they otherwise would have been.

In any case, allowed revenues would still be primarily driven by the number of customers served, but the revenue total would be driven up or down by the K factor adjustment.

Formula 11: **Revenue Per Customer** $_{\text{Allowed}}$ **=**
Revenue Per Customer $_{\text{Test Period}}$ *** K**

Formula 12: **Revenues** $_{\text{Allowed}}$ **= Revenue Per Customer** $_{\text{Allowed}}$ **X**
No. of Customers $_{\text{Actual}}$

Formula 10: **Price** $_{\text{Actual}}$ **= Revenues** $_{\text{Allowed}}$ **÷ Units Sold** $_{\text{Actual}}$

5.5 Need for Periodic Rate Cases

It is useful to have periodic rate cases in which all costs, expenses, investments, programs, policies, and tariff designs can be examined. Many regulators have required general rate cases every three to five years as part of decoupling (or set expiration dates for the decoupling mechanism). Another approach would be a built-in decline in the allowed revenue (or RPC) after three to five years. This would allow the utility to avoid a new general rate case (in which all of the utility's costs would be examined), but only if it reduced customer bills. This leaves the utility with the option to continue to retain a portion of expense containment savings motivated by decoupling (see Formula 4) without a rate case, if it can reduce costs sufficiently to give consumers a measurable benefit.

5.6 Judging the Success of a Revenue Function

One of the shortcomings of traditional utility pricing approaches is that a utility's actual revenue collection can be significantly higher or lower than its actual cost of providing service. The different revenue functions that can be applied with decoupling offer means of keeping the utility's revenue collections much closer to its actual cost of service over time. This should result in smaller rate case revenue deficiencies or excesses, lessening their associated potential for "rate shock."

A "successful" revenue function would be one that keeps the utility's actual revenue collection as close as possible to its actual cost of service throughout the period between rate cases. Indeed, the theoretically ideal result, by this standard, would be to have a zero revenue deficiency or excess in the next rate case and at most points in between, meaning that rates had tracked costs perfectly over time.

Of course, when judging the revenue function on this basis, one should disregard special circumstances that may cause a significant revenue deficiency, such as large additions to the utility's plant-in-service accounts (e.g., the addition of a new transmission line, the installation of an expensive new management information system, or the deployment of smart-grid advanced metering infrastructure).

6 Application of RPC Decoupling: New vs. Existing Customers

As much as half of the change in average usage per customer over time may be explained by differences between existing and new customers. Where new customers, on average, have significantly different usage than existing customers, their addition to the decoupling mechanism can result in small cross-subsidies.

New customers may be significantly different from existing customers. For example, new building codes and appliance standards may mean that new customers are fundamentally more efficient. Typical new homes may be larger or smaller than the average of existing homes (or may reflect a different mix of single-family and multi-family construction). If urban areas are becoming more densely populated, it may mean that new customers are closer together, and thus there is a smaller distribution system investment per customer. If line extension policies require new customers to pay a larger share of distribution system expansion costs than existing customers did, the investment added to the utility rate base per customer may be smaller for new customers. If the regulator is concerned that there may be meaningful differences between new and existing customers, it can require the utility to perform a detailed analysis of usage characteristics (quantity, seasonality, time-of-day) for each cohort of customers connected to the system.

Where new customers, on average, have significantly different usage than existing customers, their addition to the decoupling mechanism can result in small crosssubsidies

As illustrated in Table 6, new customers, on average, use 450 kWh in a billing period, but the rate case-derived RPC for existing customers is 500 kWh, application of the test year RPC values to new customers has the effect of causing old customers to bear the revenue burden associated with the 50 kWh not needed or used by new customers. This is because the allowed revenue is increased by an amount associated with 500 kWh of consumption, whereas the actual contribution to revenues from the new customers is only the amount associated with 450 kWh.

Table 6

Single RPC for Existing and New Customers			
	Existing Customers	**New Customers**	**Total**
Number of Customers	200,000	10,000	210,000
Revenue per Customer	$50.00	$50.00	
Allowed Revenues	$10,000,000	$500,000	$10,500,000
Average Unit Sales	500	450	
Decoupled Price	$0.100478	$0.100478	
Collected Revenues	$10,047,847	$452,153	$10,500,000
Average Customer Contribution	$50.24	$45.22	$50.00

To correct for this, a separate RPC value can be calculated for new customers — in our example, the amount for them would be $45.00. As shown in Table 7, the RPC allowed revenues would not be increased from $10,000,000 to $10,025,000. Instead, the increase would be equal to only $22,500.

This results in collection of an average of $50.00 from existing customers and $45.00 from new customers, thus reflecting the overall lower usage of new customers. On a total basis, the average revenues per customer are equal to $49.76. Accounting for these differences affects the *allowed* revenue to assure no over- or under-recovery, while differences in bills for these two types of customers are automatically reflected in their respective units of consumption applied to the decoupled price.

Table 7

Separate RPC for Existing and New Customers			
	Existing Customers	**New Customers**	**Total**
Number of Customers	200,000	10,000	210,000
Revenue per Customer	$50.00	$45.00	
Allowed Revenues	$10,000,000	$450,000	$10,450,000
Average Unit Sales	500	450	
Decoupled Price	$0.100000	$0.100000	
Collected Revenues	$10,000,000	$450,000	$10,450,000
Average Customer Contribution	$50.00	$45.00	$49.76

7 Rate Design Issues Associated With Decoupling

As it does with respect to increased investment in end-use energy efficiency itself, decoupling should also remove traditional utility objections to electric and natural gas rate designs that encourage conservation, voluntary curtailment, and peak load management. For example, assuming average usage of 500 kWh/month, the two following rate designs produce the same amount of revenue, but the volumetric rate provides a much stronger price signal for consumers to pursue energy efficiency:

Table 8

High vs. Low Customer Charges		
Rate Element	**High Customer**	**Low Customer**
Customer Charge	$25.00	$5.00
Usage Charge	$0.10	$0.14
Total Bill for 500 kWh average usage	$75.00	$75.00

Under volumetric pricing without decoupling, utilities have a significant portion of their revenue requirement for rate base and O&M expenses associated with throughput. In addition, those with fully reconciled fuel and purchased-power adjustment mechanisms completely recover the high cost of augmenting power supply during peak periods when expensive power resources are used, so even increased peak-period sales generate a distribution sales margin.[23] A reduction of throughput will likely reduce

23 See Subsection 3.1.1.1 above, and Moskovitz, *Profits and Progress Through Least Cost Planning,* 1990, at pp. 3-5. Fuel adjustment mechanisms are the antithesis of energy efficiency mechanisms. They guarantee that any additional sale, no matter how expensive to serve, adds to profit, and any foregone sale diminishes profitability. This is because the clauses ensure that the marginal fuel or purchase cost of incremental sales will be fully recovered, so that the non-production cost component of base rates will always contribute to the bottom line (by either increasing profits or reducing losses). www.raponline.org/Pubs/General/Pandplcp.pdf .

revenues at a greater rate than it will produce savings in short-run costs, simply because most distribution, billing, and administrative costs are relatively fixed in the short run.

Conversely, with decoupling, the utility no longer experiences a net revenue decrease when sales decline, and will therefore be more willing to embrace rate designs that encourage customers to use less electricity and gas. This can be achieved through energy efficiency investment (with or without utility assistance), through energy management practices (turning out lights, managing thermostats), or through voluntary curtailment.

Currently, the best examples of this are the natural gas and electric rate designs used by California electricity and natural gas utilities, where decoupling has been in place for many years. The residential rates applicable to most customers of Pacific Gas and Electric (PG&E), typical of those of all gas utilities and at least the investor-owned electric utilities in the state, are shown in Table 9. Both the gas and electric rates are set up with a "baseline" allocation, which is set for each housing type and climate zone. Neither rate has a customer charge, although there is a minimum monthly charge for service. If usage in a month falls below the amount covered by the minimum bill, the minimum still applies.

Table 9

PG&E Natural Gas Rate at May 1, 2008		
Rate Element	**Baseline Quantities**	**Excess Quantities**
Minimum Monthly Charge	~$3.00	
Base Rate per therm	$1.45131	$1.68248
Multi-Family Discount (per unit per day)	$0.01770	$0.17700
Low-income Discount (per therm)	$0.29026	$0.33650
Mobile Home Park Discount (per unit per day)	$0.35600	$0.35600

Table 10

PG&E Natural Gas Rate at May 1, 2008		
Rate Element	**Low Income**	**All Other Customers**
Minimum monthly Charge	~$3.50	~$4.45
Baseline Quantities	$0.83160	$0.11559
101%-130% of Baseline	$0.09563	$0.13142
131%-200% of Baseline	$0.09563	$0.22580
201%-300% of Baseline	$0.09563	$0.31304
over 300% of Baseline	$0.09563	$0.35876

7.1 Revenue Stability Is Important to Utilities

Clearly these rate designs produce a great deal of revenue volatility for the utility. Without decoupling, the utility could face extreme variations in net income from year to year. However, with decoupling, this type of rate design produces very stable earnings. The earnings per share for PG&E (the utility) for the past three years (since decoupling was restored after the termination of the California deregulation experiment) have been $1.01 billion, $971 million, and $918 million. This stability was achieved despite a $1.4 billion increase in operating expenses, mostly the cost of electricity, during this period.

The revenue stability needs of the company can conflict with principles of cost-causation as they relate to pricing. Utilities are interested in revenue stability, so that they have net income that can predictably provide a fair rate of return to investors, regardless of weather conditions, business cycles, or the energy conservation efforts of consumers. Cost-of-service considerations, however, can produce a very different result. To the extent that utility fixed costs are associated with peak demand (peaking resources, transmission capacity, natural gas storage, and liquefied natural gas (LNG) facilities) and those capacity costs are allocated exclusively to increased use in winter and summer months, the cost to consumers of incremental usage is dramatically higher than the cost of base usage.

A steeply inverted block rate design, such as those used by PG&E, correctly associates the cost of seldom-used capacity with the (infrequent) usage for which that capacity exists. Although this is arguably fair, doing so can result in serious revenue stability problems for the utility. Decoupling is one way to provide revenue stability for the utility, without introducing rate design elements such as high fixed monthly charges, in the form of a Straight Fixed/Variable rate design, that remove the appropriate price signals to consumers.

7.2 Bill Stability Is Important to Consumers

Customers also have an interest in bill stability, because in extremely cold winters or hot summers, their bills can quickly become unmanageable. Absent decoupling, rates such as those used in California, while accurately conveying the real cost of seldom-used capacity, accentuate bill volatility. In a hot summer or cold winter, consumer bills can soar as their end-block usage increases. With decoupling (and budget billing), however, customers can enjoy bill stability at the same time that utilities enjoy revenue stability, without the adverse impacts on usage that a Straight Fixed/Variable rate design can cause. When their usage (as a group) increases, the non-

production component of the rate design automatically declines, so that they pay the allowed revenue requirement (and no more) for distribution services. Conversely, when weather is unusually mild, and customer usage declines, they would pay slightly more per unit for distribution services, again ensuring the utility receives its allowed revenue. This effect is most pronounced when decoupling is applied on a current, rather than an accrual basis, as discussed later.

7.3 Rate Design Opportunities

In 1961, James Bonbright published what is considered the seminal work on ratemaking and rate design for regulated monopolies. His context was, of course, traditional price-based utility regulation, and he identified eight principles, some of which are in tension with each other, to guide the design of utility prices. That tension is demonstrated in particular by three of those principles — that rates should yield the total revenue requirement, they should provide predictable and stable revenues, and they should be set so as to promote economically efficient consumption.[24] In certain instances, more economically efficient pricing structures could lead to customer behavior that results in less stable and, in the short run, significant over- or under-collections of revenue. Decoupling mitigates or eliminates the deleterious impacts on revenues of pricing structures that might better serve the long-term needs of society. Some innovative rate designs that regulators may want to consider with decoupling include:

7.3.1 Zero, Minimal, or "Disappearing" Customer Charge

A zero or minimal customer charge allows the bulk of the utility revenue requirement to be reflected in the per-unit volumetric rate. This serves the function of better aligning the rate for incremental service with long-run incremental costs, including incremental environmental and supply costs that may already be trending upward.[25] During the early years of the natural gas industry, this type of rate design was almost universal, as the industry was competing to secure heating load from electricity and oil, and imposing fixed customer charges would have disguised the price advantage being offered and

24 Bonbright, James C., *Principles of Public Utility Rates.* Columbia University Press, New York, 1961, p. 291.

25 For electric utilities depending on coal for the majority of their supply, valuing CO2 at the levels estimated by the EPA to result from passage of the Warner-Lieberman bill (in the range of $30 to $100/tonne) would add up to $.03/kWh to $.10/kWh to the variable costs of electricity. For natural gas utilities, the environmental costs of supply are on the order of $0.30/therm, or approximately equal to total distribution costs for most gas utilities. See http://www.epa.gov/climatechange/economics/economicanalyses.html.

confused customers. Simple commodity billing was the easiest way to make cost comparisons possible for consumers. As natural gas utilities have taken on more of the characteristics of monopoly providers, they have sought to increase fixed charges.

The California utilities, under decoupling, have retained zero or minimal customer charges. In several cases, such as with the PG&E rates discussed earlier in Section 7, it comes in the form of a "disappearing minimum bill," in which customers with zero consumption pay a minimum amount, but once usage passes 100 kWh or so (and 99% of consumption is by customers exceeding this minimum), they pay only for the energy used. In December 2008, the Public Service Commission of Wisconsin approved a settlement of the parties that, among other things, created a decoupling mechanism for Wisconsin Public Service Corporation and, at the same time, reduced the level of fixed customer charges.[26]

7.3.2 Inverted Rate Blocks

Inverted block rates, of the type shown earlier for PG&E, serve several useful functions. First, they align incremental rates with incremental costs, including incremental capacity, energy and commodity, and environmental costs. Second, they recognize that upper-block usage (mostly for space conditioning) is characterized by high seasonality, usage concentrated during the peak hours, and low load-factor end-uses, all of which are more expensive to serve than other end-uses. Inverted block rates therefore properly collect the appropriate costs from these infrequent but expensive end uses. They also serve to encourage energy efficiency and energy management practices by consumers. However, they reduce net revenue stability for utilities by concentrating recovery of return, taxes, and O&M expenses in the prices for incremental units of supply, which tend to vary greatly with weather and other factors.

7.3.3 Seasonally Differentiated Rates

Seasonal rates are typically imposed in service territories whose utilities experience significant seasonal cost differences. For example, a gas utility with a majority of its capacity costs assigned to the winter months will typically have a higher winter rate than summer rate. With traditional regulation, seasonal rates reduce net revenue stability for utilities, by concentrating revenue into the weather-sensitive season.

26 Docket 6690-UR-119, *Application of the Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates*, Order of December 30, 2008.

7.3.4 Time-of-Use Rates

Rates that collect much higher amounts during the on-peak hours can convey to consumers that usage during those hours puts the entire system under stress and causes investment in new peaking capacity. However, peak-hour consumption is highly weather-sensitive, so time-of-use (TOU) rates make utility revenues more weather-sensitive, just like inverted block rates. Decoupling removes the revenue stability risk associated with TOU rates, allowing the utility to have efficient prices and still be assured of recovering non-production costs in years when weather is mild.

7.4 Summary: Rate Design Issues

A hypothetically "correct" rate design for an electric and gas utility can consist of a customer charge that recovers metering and billing costs (these are both incremental and decremental with changes in customer count) and an inverted block rate structure based on the load factors of typical end-uses. The rates shown for PG&E in California are designed along these lines.

For electric utilities, lights and appliances have steady year-round usage characteristics, and therefore the lowest cost of service. For gas utilities, water heating, cooking, and clothes drying have steady year-round usage characteristics. For both types of utilities, space conditioning (heating and cooling) loads, which are associated with the upper blocks of usage, have the lowest load factors, and therefore the highest costs of service.

Taking a hypothetical electric utility with typical meter reading and billing costs, capacity costs of $15/kW per month, and energy costs of $.05/kWh produces the following cost-based rate design:

Table 11

Cost-based Rate Design - Hypothetical Rates

Rate Element	Load Factor	Capacity Cost	Energy Cost	Total Cost
Customer Charge				$5.00
First 400 kWh Lights/Appliances	70%	$0.03	$0.05	$0.08
Next 400 kWh Water Heat	40%	$0.05	$0.05	$0.10
Over 800 kWh Space Conditioning	20%	$0.10	$0.05	$0.15

Establishing theoretically defensible rate designs such as those used by PG&E provides consumers with very clear economic signals about the costs their usage imposes, but evidence in California is that even with these high prices, utility energy efficiency programs are an essential element of a successful energy policy. The inverted rates tend to drive consumers to the programs, but if the programs are not available, they may be unlikely (or unable) to respond to the incremental cost-based prices.

Decoupling is a tool that allows the utility's interest in stable net revenues, the consumer's interest in stable bills, and the society's interest in cost-based pricing all to be met. Under decoupling, the utility can implement an inverted rate, knowing that lost distribution revenues that are incurred when sales decline will be recovered. If implemented on a "current" basis as proposed in Section 8 of this report, decoupling can also stabilize customer bills, by reducing the unit rates in months when extreme weather causes a significant variation in sales from the levels assumed in the rate case where rates are set.

8 Application of Decoupling – Current vs. Accrual Methods

Under traditional regulation, utilities have often had different adjustment factors on customer bills. Perhaps the most common is the fuel and purchased-power adjustment clause (FAC) for electric utilities and the purchased gas adjustment (PGA) clause for gas utilities. In both of these cases, utilities compute the actual costs for these items, and then customer bills are adjusted to reflect changes in those costs. There is often a lag in the determination of these costs, and the adjustment factor itself is often based on the forecast units of sales expected in the period when adjustment will be collected. As a result, actual collections usually deviate from expected collections, and a periodic reconciliation must be made to adjust revenues accordingly.

In the application of decoupling, many states use a similar approach or make the calculations on an annual basis. Any accrued charges or credits are held in a deferral account for subsequent application to customers' bills. When applied in this manner, the same reconciliation routines are used to assure collection of the amounts in the accrual account.

The variations in rates and bills caused by decoupling mechanisms are typically very small compared with those caused by FAC and PGA mechanisms. While decoupling adjustments tend to deal with variations in usage of a few percent, the price of natural gas can change by 50% or more over the year after a general rate case. Further, as described earlier, decoupling tends to moderate billing variations, whereas the FAC and PGA mechanism tend to magnify bill variations, because the cost of gas tends to rise in cold winters when demand is highest, and the cost of power tends to rise in the summer with cooling-related demands.

When a lag is present in the application of these adjustments, it has the effect of disassociating individual customers from their respective responsibility for the adjustment. The result may be a shift in revenue responsibility among those customers, and between years. For example, if a warmer-than-average winter produces a significant deferral of costs to be collected, and it is collected the following year, it is possible that the surcharge will be effective during a colder-than-average winter, exacerbating customer bill volatility, during a period when the customer is otherwise

accruing credits for the following year.

Unlike commodity adjustment clauses, however, there are no forecasting components needed in decoupling. This is true even for utilities whose rate cases use a future test year. While future test years necessarily involve forecasting the revenue requirement, the calculation of the actual price to be charged to collect that revenue requirement is a function of actual units of consumption. To calculate the price with Revenue Cap Decoupling, one need only divide the Allowed Revenue by the Actual Unit Sales. To calculate the price with RPC Decoupling, one must first derive the Allowed Revenues (based on the current number of customers), and then divide that number by Actual Unit Sales. In either case, all of the information needed to make the calculation is known at the time that customer bills are prepared. For this reason, the required decoupling price adjustment can be applied on a current rather than an accrual basis. This also means there will be no error in collection associated with forecasts of consumption and, hence, no need for a reconciliation process.

This can be done by using the same temperature adjustment data used to produce the test-year normalized results, except to calculate a daily or monthly (or more likely a billing cycle) RPC with the data, not just an annual RPC. In each billing cycle, the "allowed" RPC can be a time-weighted average of the number of days in each month of the year included in the billing cycle,[27] or it can be built up from daily information.[28]

27 For example, if the allowed RPC is $50 for March and $40 for April, and the billing cycle runs from April 16 to March 15 (i.e., 15 days in April and 15 days in March), the allowed RPC would be $45.

28 For more information on this point, see section 3.1.1.2 Non-Production Costs.

9 Weather, the Economy, and Other Risks

While traditional regulation aims to determine a utility's costs and then provide appropriate prices to recover those costs, there are a number of factors that prevent this from happening. Foremost among these are the effects of weather and economic cycles on utility sales and customer bills. These effects are directly related to how prices are set. Full or limited decoupling, and some forms of partial decoupling, will have a direct impact on the magnitude of these risks.

For the most part, full decoupling will eliminate these risks completely. Limited decoupling partially eliminates these risks. Partial decoupling may or may not affect these risks, depending upon whether the presence of a particular risk is desired.

9.1 Risks Present in Traditional Regulation

The ultimate result of a traditional rate case is the determination of the prices charged consumers. In simple terms, a utility's prices are set at a level sufficient to collect the costs incurred to provide service (including a fair rate of return — the utility's profits). Because most of the revenues are normally collected through volumetric prices, based on the amount of energy consumed or the amount of power demanded, the assumed units of consumption are critical to getting the price "right."[29]

As noted earlier, the basic pricing formula under traditional regulation is:

Formula 13: **Price = Revenue Requirement ÷ Units of Consumption**

This formula is applied using Units of Consumption associated with normal weather conditions. As long as the units of consumption remain unchanged, the prices set in a rate case will generate revenues equal to the

29 By "right," we mean consistent with the cost of service methodology.

utility's Revenue Requirement. Also, if extreme weather occurs as often as mild weather, over time the utility's revenues will, on average, approximate the revenue requirement. In theory, this protects the company from under-recovery, and customers from over-payment of the utility's cost of service — because there should be an equal chance of having weather that is more extreme or milder than normal.

With traditional regulation, in economic terms, weather-driven sales changes cause a wealth transfer between the utility and its customers which is unrelated to what the utility needs to recover and what customers ought to pay.

In reality, this is hard to accomplish, because in any given year, the actual weather is unlikely to be normal. Thus, even if the traditional methodology results in prices that are "right" and the weather normalization method used was accurate, the actual revenues collected by the utility and paid by the customers will be a function of the actual units of consumption, which are driven, in large part, by actual weather conditions, according to the following formula:

Formula 3: **Actual Revenues = Price * Actual Units of Consumption**

With this formula, extreme weather increases sales above those assumed when prices were set, in which case utility revenues and customer bills will rise. Conversely, mild weather decreases utility revenues and customer bills.

To the extent that the utility's costs to provide service due to the weather-related increases or decreases in sales do not change enough to fully offset the revenue change, then the utility will either over- or under-recover its costs. With traditional regulation, in economic terms, weather-driven sales changes cause a wealth transfer between the utility and its customers that is unrelated to the amount that the utility needs to recover and that customers ought to pay. This transfer is not a function of any explicit policy objective. Rather, it is simply an unintended consequence of traditional regulation. There is a volatility risk premium embedded in the utility's cost of capital that reflects the increased variability in earnings associated with weather risk. This premium may be reflected in the equity capitalization ratio, the rate of return, or both.

9.2 The Impact of Decoupling on Weather and Other Risks

Full decoupling causes a utility's non-production revenues to be immune to both weather and economic risk. Once the revenue requirement is determined (in the rate case or via the RPC adjustment), decoupling

adjusts prices to maintain the allowed revenue requirement. Any change in consumption associated with weather or other causes will result in an inverse change in prices, according to the following formula:

***Formula 6:* Price = Allowed Revenue ÷ Actual Units of Consumption**

As consumption rises, prices are reduced. As consumption falls, prices are increased. This means that decoupling will mitigate the higher overall bill increases associated with extreme weather and mitigate overall bill decreases associated with mild weather. With full decoupling, all changes in units of consumption, regardless of cause, are translated into price changes to maintain the allowed revenue level. Thus, no matter the amount of consumption, the utility and the consumers as a whole will receive and pay the allowed revenue. Neither the company nor its customers are exposed to weather or economic risks in this case.

Under partial decoupling, only a portion of the indicated price adjustment is collected or refunded. To the extent the adjustment falls short of recovering the indicated price adjustment, both weather and economic risks are placed upon the utility and its customers.

Under limited decoupling, the weather or economic risks may be selectively imposed on the utility and its customers. Some states have preserved the existing burden of weather risk in a decoupled environment by weather-normalizing actual unit sales before computing the new price under limited decoupling. This has the effect of fully exposing the utility and its customers to weather risk.

Conversely, one might limit the changes in unit sales to those directly attributable to efficiency programs. Lost margin mechanisms, discussed later in *Other Revenue Stabilization Measures,* are one example of this type of limited decoupling. This has the effect of preserving all of the risks, including weather and economic risks, customers and the utility bear under traditional regulation.

Any risks placed on the utility and its customers will likely increase the overall revenue requirement of the utility because of its impact on the utility's financial risk profile. This is explored further in the following section, *Earnings Volatility Risks and Impacts on the Cost of Capital.*

10 Earnings Volatility Risks and Impacts on the Cost of Capital

Utility earnings can be volatile because of the way weather and other factors influence sales volumes and revenues in the short run, without corresponding short-run impacts on costs. They can also be volatile because of the way weather and other factors influence costs in the short run, without corresponding short-run impacts on revenue (such as a drought has on a hydro-dependent utility). As a result of this volatility, utilities typically retain a relatively higher level of equity in their capital structure, so that a combination of adverse circumstances (adverse weather, economic cycle, cost pressures, and customer attrition) does not render them unable to service their debt. In addition, utilities also try to pay their dividends with current income or from retained earnings. In fact, most bond covenants prohibit paying dividends if retained earnings decline below a certain point. A utility that is forced to suspend its dividend is viewed as a higher-risk venture.

Decoupling can significantly reduce earnings volatility due to weather and other factors, and can eliminate earnings attrition when sales decline, regardless of the cause (e.g., appliance standards, energy codes, customer- or utility-financed conservation, self-curtailment due to price elasticity). This in turn lowers the financial risk for the utility, and that is reflected in the company's cost of capital.

The reduction in the cost of capital resulting from decoupling could, if the utility's bond rating improves, result in lower costs of debt and equity; but this generally requires many years to play out, and the consequent benefits for customers are therefore slow to materialize. New debt issues will carry lower interest rates, but utility bonds carry long maturities, and it can take 30 years or more to roll over all of the debt in a portfolio.

Alternatively, a lower equity ratio may be sufficient to maintain the same bond rating for the decoupled utility as for the non-decoupled utility. This would allow the benefits associated with the lower risk profile of the decoupled company to flow through to customers in the first few years after the mechanism is put in place. However, for this to be justified, the investors must have confidence that the decoupling mechanism will remain in effect for many years; a typical three-year approval period may not provide that confidence.

10.1 Rating Agencies Recognize Decoupling

The bond rating agencies have come to recognize that decoupling mechanisms, weather adjustment mechanisms, fuel and purchased-gas adjustment mechanisms, and other outside-the-rate-case adjustment mechanisms all reduce net earnings volatility and risk, and therefore contribute to a lower cost of capital for the utility. It is important when selecting "comparable" utilities for cost of capital studies to use only utilities with similar risk-mitigation tools in place, so that an apples-to-apples comparison is possible.

Standard and Poor's has explicitly recognized risk mitigation measures by rating the "business risk profile" of utility sector companies on a scale of 1 to 10. The distribution utilities without supply responsibility and with risk mitigation measures are mostly rated 1 to 3, whereas the independent power producers without stable customer bases or any risk mitigation measures are 7 to 10. The vertically integrated utilities with some risk mitigation measures are in between.[30]

The risk mitigation of decoupling can be reflected in either of two ways. First, it can be directly applied to reduce the equity capitalization ratio of the utility in a rate case. This has the effect of reducing the overall cost of capital and revenue requirement, without changing either the cost of debt or the allowed return on equity. This approach recognizes that a utility with more stable earnings does not require as much equity in its capital structure, because there is less likelihood of the utility depleting its retained earnings.

Table 12 summarizes how a change in the equity capitalization ratio reduces the revenue requirement.

Table 12

Quantification of Savings from Capital Structure Shift

Element	Allowed Return	Ratio w/o Decoupling	Ratio with Decoupling
Equity	11%	45%	42%
Debt	8%	55%	58%
Overall Return with Taxes		10.48%	10.13%
Revenue Requirement ($ millions)		$104.80	$101.30
Difference			-$3.50

30 See Standard and Poor's *New Business Profile Scores Assigned for US Utility and Power Companies: Financial Guidelines,* revised 2 June 2004. See also Moody's Investor Services, *Local Gas Distribution Companies: Update on Revenue Decoupling And Implications for Credit Ratings,* 2006, and Standard and Poor's, *Industry Report Card: U.S. Electric Utilities Well Positioned For 2011 Challenges,* December 10, 2010.

The overall impact is on the order of a 3% reduction in the equity capitalization rate, which in turn can produce about a 3% decrease in revenue required for the return on rate base, or about a 1% decrease in the total cost of service to consumers (including power supply or natural gas supply). This is not a large impact — but it is on the same order of magnitude as many utility energy conservation budgets, meaning that cost savings from implementation of decoupling can fully fund a modest energy conservation program at no incremental cost to consumers.

Cost savings from implementation of decoupling can fully fund a modest energy conservation program at no incremental cost to consumers.

It is important to recognize that this type of change involves neither a reduction in the return on equity, nor a reduction in the allowed cost of debt. It simply reflects a realignment of the amount of each type of capital required.

A utility could adapt its actual capital structure to reflect this change, either by issuing debt rather than equity for a period of months or years, or by paying a special dividend (reducing equity) and issuing debt to replace that capital.

The second approach to reflecting the risk reduction afforded by decoupling is simply to reduce the utility's allowed return on equity, discounting by some number of basis points what would otherwise have been approved. This has been done in a number of jurisdictions. There are, however, several points that regulators should consider when weighing this option against the first.

10.2 Some Impacts May Not Be Immediate, Others Can Be

If rating agencies perceive that a risk mitigation measure will be in place for an extended period, they may be willing to recognize the benefit of risk mitigation immediately upon implementation. If the risk mitigation measure is put in place only for a limited period, or the regulatory commission has a record of changing its regulatory principles frequently, the rating agency may not recognize the measure.

If the regulator does not change the allowed equity capitalization ratio when a new risk mitigation measure is implemented, the rating agency will eventually realize that the mitigation is occurring, and that earnings are more stable; and eventually a bond rating upgrade is possible. Once that occurs, the cost of debt will eventually decline, and consumers will realize the benefit of lower costs of debt in the conventional ratemaking process.

In theory, the total cost savings from a bond rating upgrade should be about the same as the savings from an equity capitalization reduction. The

principal reason for preferring the equity capitalization option is that it can be implemented concurrently with the imposition of the risk mitigation measure, so that consumers receive an immediate economic benefit when the measure is implemented. The lag to a bond rating upgrade can be years, or as much as a decade; and the cost savings will phase in very slowly as new bonds are issued.

10.3 Risk Reduction: Reflected in ROE or Capital Structure?

Some ratepayer advocates have proposed an immediate reduction in the allowed return on common equity as a condition of implementing decoupling. This may create controversy in the ratemaking process, with the risk that utilities then become resistant to implementation of decoupling. Utilities have pointed to rate cases in other jurisdictions, where many of the "comparable" utilities used to estimate the required return on equity already have risk mitigation measures in place.

Economic theory supports the notion that risk mitigation is valuable to investors and that that value will (eventually) be revealed in some way in the market — through a lower cost of equity, a lower cost of debt, or a lower required equity capitalization ratio. Any of these will eventually produce lower rates for consumers, in return for the risk mitigation measure. Regardless of the theory, however, utilities may tend to view a reduction in the return on equity as a penalty associated with decoupling. In contrast, a restructuring of the capitalization ratio does not necessarily alter the required return on equity, and it is more directly reflective of the risk mitigation that decoupling actually provides — that is, stabilization of earnings with respect to factors beyond the utility's control. By reducing volatility, the utility needs less equity to provide the same assurance that bond coverage ratios and other financial requirements will be met.

Rating agencies have recognized the linkage between risk mitigation and the required equity ratio to support a given bond rating, rather than to the required return on equity. For this reason, there may be advantages to focusing on the utility's capital structure, rather than on its allowed return on equity or the cost of debt, when regulators consider how to flow through the risk-mitigation benefits of decoupling to consumers when a mechanism is put into place.[31]

31 One recent paper concluded that decoupling did not result in a decrease in the cost of equity capital in the short run. The study focused on only one approach to measure the cost of capital, the discounted cash flow method. It did not consider the reduction in systematic risk (the change in earnings relative to the change in the overall market earnings in the same period) that is measured by the Capital Asset Pricing Model. Decoupling will reduce systematic risk (reducing earnings volatility due to economic cycles) because sales variations in business cycles do not affect earnings under decoupling. The study also did not

10.4 Consumer-Owned Utilities

Consumer-owned utilities (COUs) do not pay cash dividends, but they do need to maintain a sound bond rating to support future investments. The rating agencies look at the TIER (times interest earned ratio) of COUs.[32] Typical bond covenants for COUs obligate the utility to maintain its TIER above a minimum defined level, so they might be required to raise rates if they suffered severe earnings attrition (from any cause).

A loss of revenue due to conservation, weather, or other factors can impair the TIER, and therefore the borrowing capacity of a COU. A decoupling mechanism will provide the same stability of earnings for a COU as for an investor-owned utility (IOU). However, there is a smaller body of research on whether decoupling will actually have a meaningful effect on the borrowing costs of COUs, assuming that their TIER remains within a range in which they are able to borrow.

Without decoupling, COUs tend to set rates at levels that provide 75%-90% assurance that the TIER will remain at an acceptable level. It is clear that a decoupling mechanism will ensure that the TIER remains in an acceptable range, and that the COU will be able to borrow. A decoupling mechanism may thus allow a COU to set rates at a slightly lower level, without fear that a variation in weather or sales will cause it to fall to a level that would trigger a larger rate adjustment.

10.5 Earnings Caps or Collars

Some commissions have imposed an earnings cap, or an earnings collar, as part of a decoupling mechanism. These ensure that, if earnings are too high above a baseline (or too low below the baseline), the decoupling mechanism is automatically subject to review. Because decoupling reduces earnings volatility, it should be unlikely for earnings to vary outside a range of reasonableness. Therefore such a cap or collar, while unlikely to be triggered, may provide greater comfort with the change represented by decoupling.

Even so, in practical application, it is simpler to impose a cap on the variability in prices than in earnings, because the calculation of earnings for regulatory purposes can be significantly different than earnings reporting under generally accepted accounting principles and may invite disputes over methodology.

attempt to measure the change in probability that a utility would exhaust its ability to pay dividends from cash earnings, which is reduced if the utility is protected from variations in earnings driven by weather and economic cycles. These are factors that lead RAP to believe that adjusting the capital structure is more appropriate than adjusting the allowed return on equity when decoupling is implemented on a permanent basis. See Brattle Group, The Impact of Decoupling on the Cost of Capital, March, 2011.

32 TIER is a measure of the extent of which earnings are available to meet interest payments. Mathematically it is defined by this formula: TIER = (net income + interest) / (interest).

11 Other Revenue Stabilization Measures, and How They Relate to Decoupling

There are a number of other revenue stabilization measures used by regulatory commissions, some of which are proposed as possible alternatives to decoupling. Some of these provide nearly the same benefits to utility shareholders as decoupling, but all of them fall short of the full range of benefits that revenue decoupling provides, particularly those for consumers and the environment. We discuss several of these below, comparing the consumer impacts and societal benefits to those of decoupling.

11.1 Lost Margin Recovery Mechanisms

A lost margin mechanism provides recovery to the utility for distribution margin that is lost when customers participate in the utility-sponsored energy efficiency programs. The benefit is that the utility resistance to offering such programs is addressed. One side effect is creation of a bias in favor of utility-funded programs to the exclusion of codes, standards, and other lower-cost means to achieve savings. In one experience, a utility was simultaneously offering incentives for participation in its programs, while conducting a political campaign against other types of energy efficiency marketing, to ensure that any lost margins were recovered.

11.2 Weather-Only Normalization

Typically the largest rate adjustments under decoupling are weather-induced. Many natural gas utilities have weather normalization clauses, in which small surcharges are imposed during periods of mild weather, and small surcredits during severe weather. A weather-only adjustment does not address lost sales due to either programmatic energy efficiency on consumer-funded energy efficiency, and therefore does not address one of the principal objectives of decoupling, which is to eliminate utility disincentives for energy efficiency.

11.3 Straight Fixed/Variable Rate Design (SFV)

SFV is an approach to rate design in which all utility fixed costs are recovered in a fixed monthly charge, with only variable costs included in the per-therm or per-kWh rate. The definition of "fixed" costs varies from a strict accounting measure (interest and depreciation) to a broad measure that includes the return on equity, taxes, and labor expenses, but the principle is the same: customers do not pay for utility service on a primarily volumetric basis.

SFV is attractive due to simplicity, but has numerous adverse side effects. These include:

- Energy prices are set far below long-run marginal cost, leading to uneconomic usage;
- Small users, particularly seniors and apartment dwellers, pay much higher electric and gas bills;
- Consumer investment in energy efficiency is discouraged, since the bill savings are small;
- A mismatch occurs between the cost-responsibility and cost-collection for seldom-used peaking facilities (for which the costs should be recovered in incremental usage block rates).

Some studies have estimated that SFV pricing can cause usage to go up 10% or more, enough to offset much or all of the benefit of energy efficiency programs.[33]

11.4 Fuel and Purchased Energy Adjustment Mechanisms

Fuel adjustment clauses (FACs) and purchased gas adjustment (PGAs) mechanisms are used by nearly all gas utilities, and by most electric utilities, to recover variable costs of fuel and purchased energy. They evolved during the first and second oil embargoes in 1973 and 1977, and have become nearly ubiquitous. The benefit of these is that utilities are assured of recovery of a very large set of costs over which they have little control. The side effect is that an FAC or PGA ensures that ANY incremental sale is profitable, since ALL of the increased variable cost is covered, and the incremental sales margin results in incremental profit.

33 See *Pricing Do's and Don'ts,* www.raponline.org/docs/RAP_PricingDosAndDonts_2011_04.pdf

FACs and PGAs are therefore of great concern when trying to design a regulatory framework that encourages utility support of energy efficiency.[34] A properly designed decoupling mechanism can overcome this effect by assuring that only the allowed level of non-fuel or non-power revenues are received if utility sales increase.

11.5 Independent Third-Party Efficiency Providers

Several states have implemented third-party energy efficiency utilities, such as Efficiency Vermont and the Energy Trust of Oregon. Some advocates believe that by moving efficiency outside the utility, there is no longer a need for revenue decoupling, because the utility is no longer in a position to resist or obstruct energy efficiency investment. It is instructive that both Vermont and Oregon have found that revenue decoupling is a useful addition to a framework that includes a third-party provider, because utilities affect energy efficiency in many more ways than simply making grants and loans to consumers for energy efficiency measures.

11.6 Real-Time Pricing

Some academics have taken the position that dynamic utility pricing will result in efficient deployment of energy-efficiency measures, without any need for government or utility intervention. While advanced pricing has many advantages, it does not in any way overcome the multiple barriers to energy efficiency — such as access to capital, perfect information, or short time horizons of consumers, particularly renters. These barriers have been well-documented, and no form of energy pricing has been demonstrated to overcome them.

34 See Moskovitz, David, *Profits and Progress Through Least Cost Planning* for a detailed discussion of the problems with FACs and PGAs at: http://www.raponline.org/docs/rap_moskovitz_leastcostplanningprofitandprogress_1989_11.pdf

12 Decoupling Is Not Perfect: Some Concerns Are Valid

There are many critics of decoupling, and many different issues that they criticize. Decoupling is not a perfect form of regulation — but neither is conventional regulation. Both seek to set prices for utility service that approximate the cost of providing that service. Both seek to provide incentives for management to take actions to reduce costs and to maximize profits.

In this section, we discuss some of the common critiques of decoupling mechanisms, recognizing that all forms of regulation involve compromise.

12.1 "It's an annual rate increase."

Some rate case participants view decoupling as an annual rate increase without a rate case. This may be the case if the use per customer is declining over time, but it does not provide any indication of whether customer energy bills are rising or falling. That may be due to utility programs and policies, or it may be due to other factors that can be taken into account in the design of the decoupling mechanism.

If the decline in usage per customer is due to utility programs and policies, an annual upward rate adjustment (which produces annual decreases in annual bills due to declining usage) may be exactly why the decoupling mechanism was created. If energy efficiency is less expensive than energy production, then customer energy bills are declining. Absent decoupling, the utility would likely be filing annual rate cases, creating a significant workload on the Commission and leading to similar rate increases, since the underlying causes are the same.

To the extent that less frequent rate cases produce fewer opportunities for consumers to present policy issues to the Commission, it is probably appropriate for the regulator to create an alternative forum for such policy review. One approach, for example, might be for the regulator to initiate a general rate case at least once every three to five years, to ensure that the allowed revenues under decoupling do not deviate too far from the utility's underlying costs.

12.2 "Decoupling adds cost."

This reflects a misunderstanding of decoupling. Decoupling increases the likelihood that the revenue requirement found appropriate in a rate case will be the amount actually collected from customers. Certain decoupling elements (e.g., adjustments for inflation, productivity, and numbers of customers) project how those approved costs might change, and allow these changes to be reflected in future collections; but these changes represent costs that are likely to be approved in a rate case, because they are essential to providing service. Decoupling itself adds no significant new costs; to the extent that decoupling reduces the frequency of general rate cases, it can significantly reduce regulatory costs.

12.3 "Decoupling shifts risks to consumers."

Full decoupling means that utility profits are no longer adversely affected by weather conditions that reduce sales volumes, and some critics consider this a shift of weather risk to consumers. This is a fundamentally flawed argument. First, decoupling also removes the profit enhancement that occurs under traditional regulation when weather conditions cause sales increases. Second, with current decoupling, although prices go up when sales go down, they do so simultaneously, so that customer bill volatility is reduced, a benefit to consumers attempting to live within a budget. In addition, when sales go up, prices come down, thereby mitigating the bill's impacts. In this sense, decoupling mitigates earnings risk for utilities and expense risk for consumers, making both better off — and in the process, it creates the earnings stability to justify a lower overall cost of capital, which reduces absolute costs to consumers.

12.4 "Decoupling diminishes the utility's incentive to control costs."

In fact, precisely the opposite is true. Decoupling does not guarantee utilities a level of earnings, only an assurance of a level of *revenue*. If the utility reduces costs, it increases earnings, just as it would under traditional regulation. Also, because the utility cannot increase profits by increasing sales, improved operational efficiency is the *only* means by which it can boost profits.

Because decoupling provides recovery of lost margin due to customer conservation efforts, however, it may extend the period between general rate cases. This is particularly true if aggressive utility conservation efforts are producing significant declines in customer usage; absent decoupling,

this sales decline will trigger rate cases. This longer time period provides a stronger incentive for the utility to achieve operational efficiencies and reduce costs, because the utility will be allowed to retain the cost savings for a longer time, until the next general rate case. If costs and revenues become unbalanced for any reason, the utility or the regulator can initiate a general rate case at any time.

12.5 "What utilities really want sales for is to have an excuse to add to rate base —that is, the Averch Johnson Effect."

In a rate case, the net-income line item in the cost of service is a function of the size of the rate base and the return allowed>>. The greater the rate base, the greater the net income that is included in the cost of service (for a given allowed return). Utilities may be motivated to increase sales in order to add to rate base capital assets needed to serve additional load, despite countervailing risks associated with permitting and construction, for instance. This is not a concern decoupling can address, nor is it intended to address. Rather, sound integrated resource planning that identifies the least-cost long-term resource acquisition strategy is the best way to manage incentives associated with the capital program.

12.6 "Decoupling violates the 'matching principle'."

The matching principle in ratemaking is an implicit assumption that revenues, sales, and costs will move in synchronization: as sales change (go either up or down), revenues and costs will change at the same rate. Absent changes in customers, programs, or policies, this has been generally effective in allowing traditional regulation to function effectively. Implied in the matching principle is that inflation is offset by productivity, and that new customers are about the same in terms of usage, revenue, and cost of service as existing customers. However, as discussed in the sections *How Traditional Regulation Works and How Decoupling Works,* it is the very fact that the matching principle does not hold true (that is, that marginal revenue almost always exceeds marginal cost in providing distribution service) that drives the need for decoupling.

Correspondingly, a change to a more comprehensive approach to energy efficiency means that deliberate programs and policies are implemented to achieve sales reductions for which there are no corresponding cost reductions, at least (for the most part) in distribution services. The very circumstances that counsel most regulators to consider decoupling — a desire to step up the rate of achievement of customer energy efficiency — directly undermine the foundation of the matching principle.

12.7 "Decoupling is not needed because energy efficiency is already encouraged, since it liberates power that can be sold to other utilities."

This condition does exist in some low-cost utilities that have excess capacity available for sale and that do not have FACs. Any utility with a traditional FAC does not benefit from off-system sales, because those revenues are credited to their retail consumers through the adjustment clause.

This concern, however, overlooks the temporary nature of excess capacity, especially if some of it is the result of an aging generation approaching retirement, and the changing nature of power markets. Decoupling encourages utilities to take actions that may increase off-system sales revenues, but only if power costs are covered by a decoupling mechanism will those sales result in increased profits for the companies.

Lastly, off-system sales have less certainty and are subject to the vagaries of market prices, whereas sales to native loads are more certain and subject to less price volatility. Conservative utility managers are likely to prefer the "bird in hand" in such cases.

12.8 "Decoupling has been tried and abandoned in Maine and Washington."

Maine and Washington initiated decoupling mechanisms in the late 1980s and early 1990s, and both terminated the programs after a few years. The reasons for termination were different.

In Maine, the decoupling mechanism was instituted for Central Maine Power shortly before a serious recession hit the country. Sales declined and the decoupling mechanism generated significant rate increases, because of the large annual adjustment resulting from the use of an accrual methodology. The Commission elected to discontinue the mechanism. Of course, for the most part, decoupling only implemented what a new rate case would have yielded in any event, the root cause of the problem not being the mode of regulation, but the recession. The lesson learned is that a cap on annual rate increases may be appropriate, and a complete review of costs, sales, and revenues (i.e., a general rate case or equivalent) should be required every few years under a decoupling mechanism.

In Washington, a decoupling mechanism applied to "base costs" was introduced at the same time that a separate mechanism was introduced to recover "power costs." The utility (Puget Sound Power and Light Company) was acquiring significant new resources to replace expiring power supply contracts. Rates went up sharply due to the operation of the power cost mechanism, not the decoupling mechanism. The increases raised public

concerns, and the public utility commission (PUC) opened an inquiry into the Puget's resource decisions. The Commission found that, with respect to certain power supply contracts, the utility had acted imprudently. The combined mechanism was terminated. The rate adjustments due to the decoupling portion had been minor, and were not the primary focus of the Commission's inquiry. Shortly thereafter, Puget applied for a merger with Washington Natural Gas Company. A multi-year rate plan was approved as part of the merger, displacing both the power-cost and base-cost decoupling mechanisms.

12.9 "Classes that are not decoupled should not share the cost of capital benefits of decoupling."

Many commissions have excluded large-volume electricity and natural gas consumers from decoupling mechanisms. The reason for this is that classes of customers with few members may really require customer-specific attention in ratemaking, and a decoupling mechanism could result in significant rate increases to remaining customers if another customer or customers in the class discontinued or reduced operations.

Because decoupling results in a lower risk profile for the utility, particularly with respect to weather and economic cycles, it is expected (either immediately or over time) that a reduction in the cost of capital will result. A class that is not exposed to decoupling rate adjustments due to sales variations is not a part of the cause of the lower risk profile. However, because Commissions normally apply the same rate of return to all classes, it may not be pragmatic to calculate a different rate of return for each class.

As a practical matter, large-use customer classes often have other revenue stabilization elements in their rates, such as contract demand levels, demand ratchets, and straight fixed/variable rate designs that have a stabilizing effect on revenues similar to that of decoupling. Consequently, one might argue that, under traditional regulation, the classes with more variable loads were benefiting from the risk-reducing nature of larger-volume customers, and that decoupling merely balances the scales.[35]

35 But it is fairer to say that all loads impose both risks and benefits on the utility. A large-volume user may have a higher-than-average load factor and provide stable revenues to the utility, but the adverse impacts of its leaving the system are significantly greater than those of individual lower-volume customers. Many factors affect the market's valuation of the risks that a utility faces; load diversity is only one of them.

12.10 "The use of frequent rates cases using a future test year eliminates the need for decoupling."

A future test year may have the effect of causing a utility's "revenue requirement" to more closely track a utility's revenue requirement over time. A future test year does not, however, have the effect of constraining *allowed revenues* to a utility's revenue requirement. In addition, a future test year does not address the throughput issue, which is one of the primary reasons for using decoupling. The term "decoupling" itself is rooted in the notion of separating the utility's incentive to increase profits through increased sales, and to avoid decreased profits through decreased sales by breaking the link between — that is, by decoupling revenues from sales.

12.11 "Decoupling diminishes the utility's incentive to restore service after a storm."

This can be a problem if not addressed in the design of the decoupling mechanism. After a storm, utilities normally bring in extra crews, pay overtime, airlift in supplies, and otherwise do everything reasonably possible to restore service. The primary reasons for this are the deeply-held sense of obligation that drives utilities and their employees to provide reliable service and their appreciation of the far-reaching and deleterious impacts of an outage.

But there is also a more prosaic motive: the need to "get the cash register running" again, so revenue flows to the utility. If a decoupling mechanism allows the utility to receive the revenues that it would have collected if the power were on, consumers both suffer an outage and pay for service they did not receive. The utility is made whole, and really does not suffer any penalty from slow service restoration.

This is easily addressed in the design of an RPC decoupling mechanism. One approach would be to adjust the number of customers for whom the allowed revenue is computed to reflect only those who were receiving service during a particular time period, deducting days when power was unavailable. (This same concern applies equally to straight fixed/variable pricing: the charges to consumers must be halted during an outage, or the incentive to restore service is diminished.) Another approach would be to address service quality issues such as outages separately, in a comprehensive Service Quality Index, with penalties tied to outage frequency and duration.

12.12 "The problem is that utility profits don't reward utility performance."

At least two states have tried to overcome utility resistance to energy efficiency investment by allowing a higher rate of return for investment in energy efficiency than utilities receive on supply-side investments. While this can work in theory, it is difficult to make it work in practice, because the incentive return must be quite high to overcome the lost margin effect that decoupling addresses. In addition, a premium return may tend to reinforce the Averch-Johnson effect, giving utilities an incentive to spend as much as possible (to attract the incentive return) on measures that save little or no energy (to avoid creating lost margins). An incentive return mechanism can be a very important part of regulation, for example, by tying the utility's return (or the utility's recovery of deferral margins under decoupling) to the utility's achievement of energy efficiency achievement and cost control targets approved by the commission. But, as a general matter, incentive return mechanisms have not been effective alternatives to decoupling; in combination *with* decoupling, however, they can be.

13 Communicating with Customers about Decoupling

Preparing a utility's customers for the effects of decoupling on their bills can be a challenge, both because the components of a utility's bill are not always straightforward, indeed are often confusing, and because variable prices are a new phenomenon to most. Regulators, utilities, and consumer advocates should all want to make the transition to decoupling as smooth as possible for customers. This requires some thought about bill design and consumer education. The guiding principle here should be simplicity. In fact, the implementation of decoupling offers an opportunity to overhaul the utility's bill with an eye toward simplification.

In many states, the utility bill has become a rather dense tangle of line items that represent, in many cases, a long history of policy initiatives and regulatory decisions. In many cases, they are a kind of tally of the rate-case battles won and lost by advocates and utilities, a catalogue of special charges and "trackers" dealing with particularly knotty investment and expenditure requirements. The accumulated result is often a bill that consumers find difficult to navigate. A customer's electric bill typically consists of a monthly customer charge, one or more usage blocks (or time-of-use periods), and as many as ten surcharges, credits, and taxes added to these usage-related prices. Some utilities present all of the detail on the bill, and it can be confusing and overwhelming to the consumer. Table 13a shows an example of how the customer's bill may look with all of the detail. To the extent that line items can be eliminated or combined, consumer confusion is likely to be reduced.

Alternatively, all of the detail can be provided, but the bill should "roll up" all of the rate components, adjustments, taxes, surcharges, and credits into an "effective" rate that the consumer pays. Table 13b shows what the customer actually pays if they use more electricity, or saves if they use less electricity. Utilities should be encouraged to display the "effective" rate to customers, including all surcharges, credits, and taxes, so consumers can measure the value of investing in energy efficiency or other measures that reduce (or increase) their electricity consumption.

Tables 13a and 13b show a conversion of a rate with multiple surcharges into an effective rate.

Table 13a

Example of an electric bill that lists all adjustments to a customer's bill.

Your Usage: 1,266 kWh			
Base Rate	**Rate**	**Usage**	**Amount**
Customer Charge	$5.00	1	$5.00
First 500 kWh	$0.05000	500	$25.00
Next 500 kWh	$0.10000	500	$50.00
Over 1,000 kWh	$0.15000	266	$39.90
Fuel Adjustment Charge	$0.01230	1,266	$15.57
Infrastructure Tracker	$0.00234	1,266	$2.96
Decoupling Adjustment	$(0.00057)	1,266	$(0.72)
Conservation Program Charge	$0.00123	1,266	$1.56
Nuclear Decommissioning	$0.00037	1,266	$0.47
Subtotal:	$139.74		
State Tax	5%		$6.99
City Tax	6%		$8.80
Total Due			**$155.53**

Table 13b

The rate above, with all of the surcharges, credits, and taxes applied to each of the usage-related components of the rate design.

Base Rate	**Rate**	**Usage**	**Amount**
Customer Charge	$5.56500	1	$ 5.56
First 500 kWh	$0.07309	500	$ 36.55
Next 500 kWh	$0.12874	500	$ 64.37
Over 1,000 kWh	$0.18439	266	$ 49.05
Total Due			**$155.53**

A secondary issue is whether the changes in price occasioned by decoupling should, themselves, be detailed in a line item on the bill or subsumed in a total price. We are all familiar with changing prices at the gas pump, but do not expect a "line item" description of the latest adjustment up or down in that price. We expect to pay the price on the sign, and expect it to include all taxes, fees, profit, transportation charges, and other elements of cost. In fact, if gas stations were required to track price changes in such a way, consumers would see a confusing array of information that is largely unrelated to changes in the total price being paid. Again, simplicity argues for rolling the decoupling adjustments directly into the total price, rather than having a separate decoupling adjustment line item. The full detailed tariff must be available for the customer to review, generally on the utility website, but it may not need to be on the bill; only the effective prices – what a customer pays if he or she uses more or less service – is relevant to the consumption decision.

When decoupling is implemented, a communication strategy should be in place to help consumers understand why prices are being allowed to vary from bill to bill. They may see decoupling as a "profit guarantee" rather than a "revenue assurance." Information making clear the ultimate impacts of decoupling will likely be more understandable than a brochure that attempts to, say, summarize the contents of this guide.

Aside from the total size of their bills, customers tend to be most concerned about whether they are being fairly charged by their utility. Decoupling strikes to the heart of this issue because, unlike traditional regulation, it has a high probability, if not certainty, that consumers will actually pay the revenue requirement determined by the Commission. In addition, where weather risk is eliminated, decoupling has the effect of countering the impacts of high bills during extreme weather (with the symmetric effect of slightly increasing bills during mild weather).

Most consumers would likely welcome a little "help" when the bills are higher than usual, at the "cost" of a slightly higher bill when bills are lower. This is merely the softening of the peaks and valleys. It is these aggregate effects that consumers should understand, and which a communication strategy should address.

14 Conclusion

Revenue regulation and decoupling provide simple and effective means to eliminate the utility throughput incentive, remove a critical barrier to investment in effective energy efficiency programs, stabilize consumer energy bills, and reduce the overall level of business and financial risk that utilities and their customers face.

This guide has identified and explained key issues in decoupling for the benefit of regulators and participants in the regulatory process alike. Each utility and each state will be a little bit different, so there may not be a cookie-cutter approach that is right for all. However, the principles remain fairly constant: minor periodic adjustments in rates stabilize revenues, so that the utility is indifferent to sales volumes. This eliminates a variety of revenue and earnings risks, in particular those associated with effective investment in end-use energy efficiency, and can bring provision of least-cost energy service closer to reality for the benefit of utilities and consumers alike.

Revenue Regulation & Decoupling:

A Case Study

RAP

Revenue Regulation & Decoupling: Case Study

The Regulatory Assistance Project

Contents

Decoupling: A Case Study

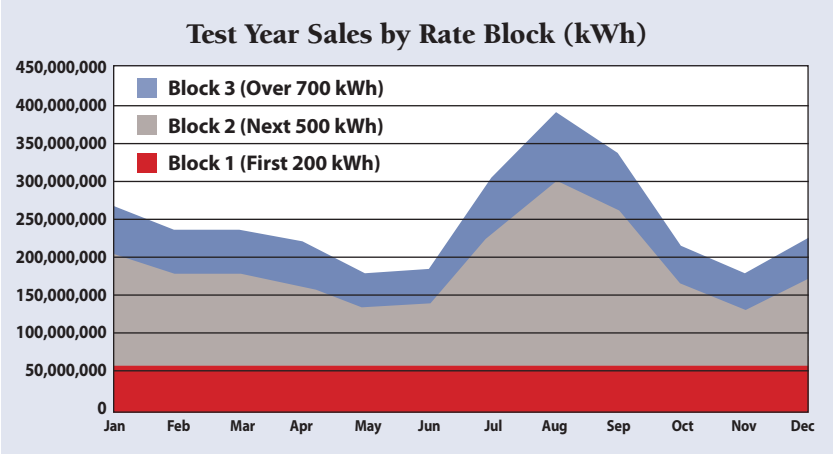
The following is a simple case study that demonstrates many of the properties of decoupling. The study concept is to model the impacts of decoupling on a single class of customers, in an environment where fairly aggressive demand-side reductions are being achieved. The analysis is intended to focus on the decoupling impacts driven by those reductions. Except for the abnormal weather comparison, weather is ignored – i.e., assumed to be "normal" in all years.

The model uses a single "test" period as a beginning point, as a rate case would provide, and then analyzes results for the following three-year period on a monthly basis. An analysis of an accrual method for decoupling is shown at the end of this case study.

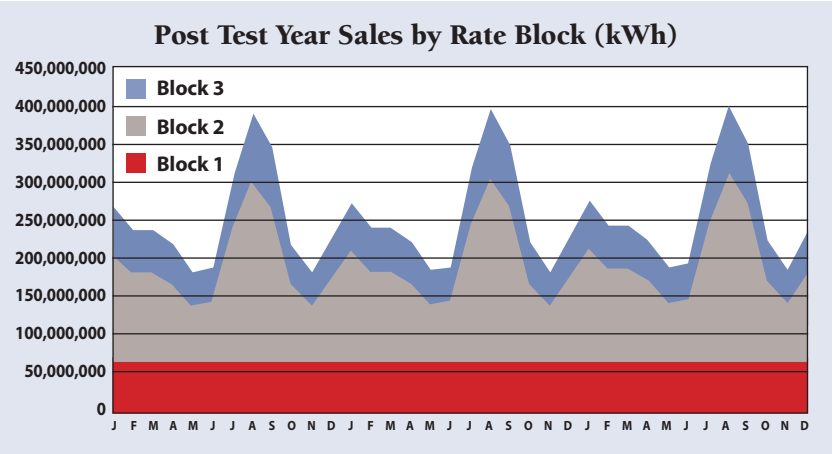
Characterization of the Prototypical Utility Residential Rate Class

Source Data

The general scale and structure of our prototypical utility is derived from data for the residential class in a recent rate proceeding for Public Service Company of New Mexico (PNM)[1].



[1] However, this analysis is not intended to be, nor is it, an attempt to "model" PNM. PNM data was used solely to establish a reference for scale (numbers of customers and their consumption patterns) and for an associated set of prices.



The study begins with annual consumption and pricing information from the rate case. That consumption level was then allocated across the months of the years to reflect normal weather. Resulting *Test Year Sales* are shown on the previous page. Weather data are from the National Weather Service for Albuquerque. Weather data are used solely to seasonalize annual sales amounts.

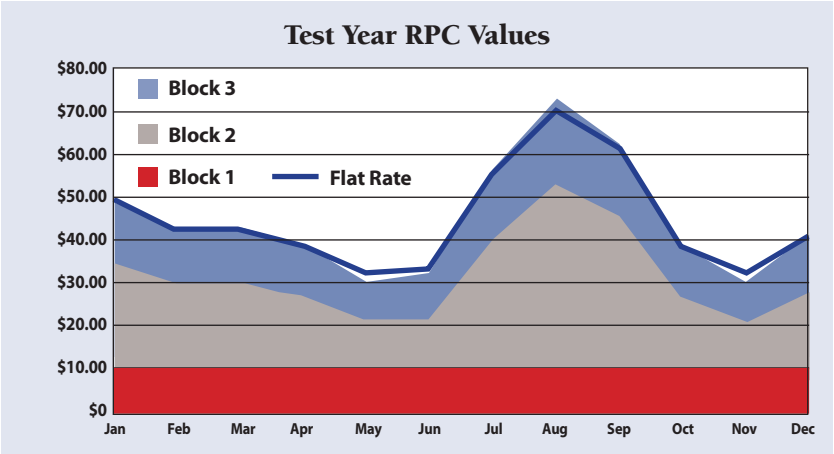
PNM's original block rates for residential customers were also seasonal, with higher rates in the June-August period. For simplicity, the model is based on revenue-equivalent non-seasonal block rates.

For bill analyses, fuel costs are the same fuel costs as in the PNM data — $0.020243/kWh. For bill analyses, avoided fuel costs are also assumed to be $0.020243/kWh. This has the effect of *slightly* understating the bill savings from energy reductions, because the marginal fuel cost should be at least somewhat higher (possibly much higher) than the average.

Scenario Parameters

Customer Growth

The model requires a few significant inputs to characterize a scenario. The most important of these is the customer growth grate, which drives increases in allowed revenues through the revenue per customer (RPC) mechanism. For this case study, customers are assumed to grow at a 2.0% annual rate, on a beginning base of approximately 405,000 customers. For simplicity, new customers are assumed to have identical consumption patterns as existing customers. If new customers are using more (or less) power than existing customers, or have different seasonal or time-of-use patterns, the growth in revenues will not be linear with the growth in customers, and an adjustment to RPC decoupling may be needed.



Business as Usual Sales

Monthly energy sales for the *business as usual* case are shown below>>. Block 1 sales are assumed to experience no seasonal variation. Block 3 sales are assumed to reflect the full seasonality of normal weather. Block 2 sales are assumed to experience one quarter of the variability of Block 3 sales.

RPC Values

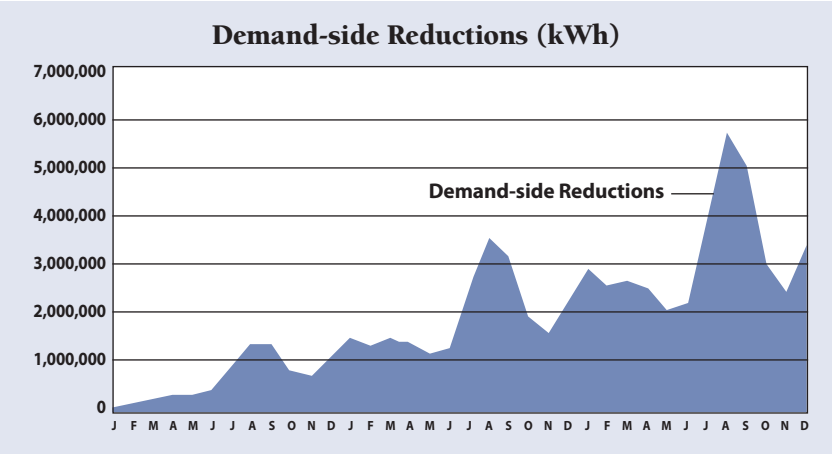
Applying Test Years Sales to the tariff prices, yields total revenues per rate block. These are then divided by the number of customers to derive the allowed RPC values for each rate block. The results are shown at right. These values will be used to compute allowed revenues for Post Test Year periods, based on the number of customers then being served.

Demand-side Reductions

The other significant input assumptions are the percentages of sales growth that are offset by demand-side reductions. Because the primary sales data in the model is constructed around an inclining 3 block rate design, the reductions in sales can be, and are, separately allocated to each block. For this case study, 50% of the growth in Block 3 is assumed to be avoided through demand-side reductions. For Block 2, 25% of the growth is assumed to be avoided, and for Block 1, 5% of the growth is avoided.

Avoided Costs

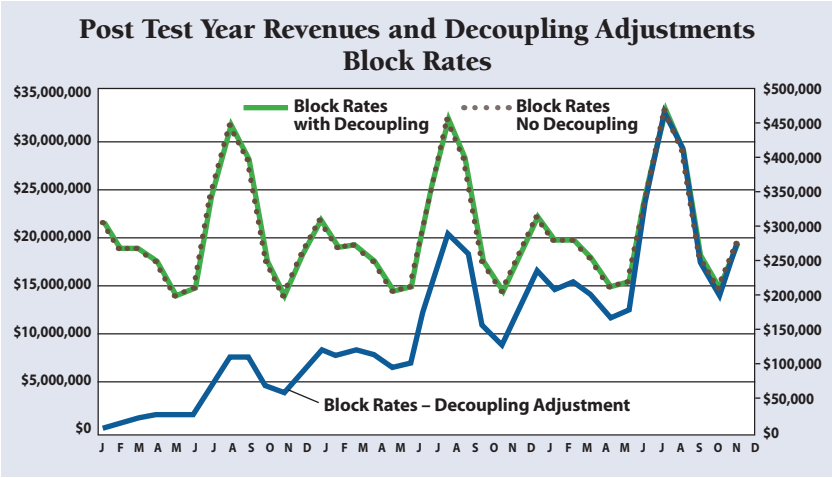
This study assumes that in the short run the only costs that will be avoided by the utility are those that flow through the fuel adjustment clause. If the utility is able to sell power off-system, or avoid purchases, we assume



that those revenues or costs flow through the fuel mechanism. The power plant inventory is assumed to be unchanged, and load variations are met exclusively by either dispatching utility-owned generation or by making spot market purchases and sales of power. If the utility were adding resources, particularly independent power producer (IPP) IPP-owned generation in which all costs (not just variable costs) flow through the fuel adjustment mechanism, a different modeling approach would be required.

Current Period Decoupling

In each example below, we assume that the utility is implementing current period decoupling, meaning that lost distribution margins due to sales variation are recovered in the billing cycle in which the sales reductions



occur. This is easily modeled, and fairly easy to implement, but some commissions have chosen to implement deferred recovery of decoupling surcredits and surcharges, usually on an annual basis. It would mask the impact of decoupling to present the effect on a deferral basis.

Decoupling Adjustment Results

RPC decoupling has the effect of offsetting the reduction in revenues caused by reductions in sales, with the objective of tracking actual non-fuel revenues with the results of the last rate case. As shown at right, total revenues are driven upward to restore reduced sales from demand-side reductions. The bottom line represents the monthly revenue associated with decoupling. This amount grows as the magnitude of demand-side reductions increases.

Comparing Different Rate Designs in a Decoupled Environment

Rate Designs Compared

The case study analyzed three different rate designs in a decoupled environment for this residential customer class: inverted block rates, flat rates, and straight-fixed variables rates. Inverted block rates have increasing prices as overall consumption increases over three tiers of consumption: first 200 kWh, the next 500 kWh, and over 700 kWh. Flat rate designs have a single volumetric price for all consumption. Straight-fixed variable rates collect all non-production costs through a customer charge. Each of the assumed rate designs collects $239.2 million in annual revenues, and is reflected in Table 1 (production costs are recovered separately through a fuel and purchased power adjustment tariff rider):

Table 1

Non-Seasonal Inclining Block Rate Design				
Price Type	**Total Revenue**	**Total Determinants**	**Rate Billing**	**Rate Units**
Customer Charge	$19,484,784	4,871,196	$4.00	$/mo.
Block 1 (First 200 kWh)	$47,640,783	898,696,181	$0.05301	$/kWh
Block 2 (Next 500 kWh)	$109,014,161	1,395,256,018	$0.07813	$/kWh
Block 3 (>than 700 kWh)	$63,067,176	709,610,240	$0.08887	$/kWh
Demand	$ -	-	$ -	$/kW
Non-Seasonal Flat Rate				
Price Type	**Total Revenue**	**Total Determinants**	**Rate Billing**	**Rate Units**
Customer Charge	$19,484,784	4,871,196	$4.00	$/mo.
Energy Charge	$219,722,120	3,003,562,439	$0.07315	$/kWh
Demand	$ -	-	$ -	$/kW
Non-Seasonal Straight-Fixed-Variable Rate (SFV)				
Price Type	**Total Revenue**	**Total Determinants**	**Rate Billing**	**Rate Units**
Customer Charge	$239,206,904	4,871,196	$49.11	$/mo.
Energy Charge	$ -	3,003,562,439	$ -	$/kWh
Demand	$ -	-	$ -	$/kW

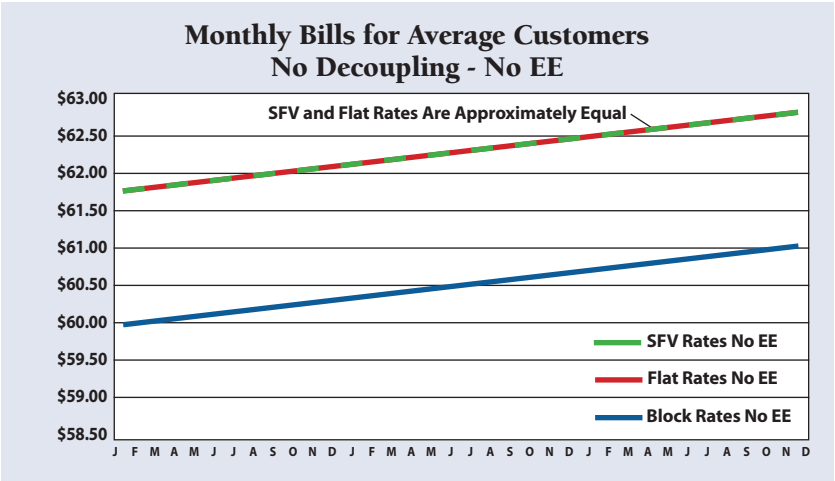
Description of Bills: Low, Average, and High

The case study looks at three different types of customers, a low usage (150 kWh/month), average usage (617 kWh/month), and high usage (1500 kWh) customer. No attempt was made to seasonalize the usage of such customers (but the underlying usage and the savings from efficiency investments are reflected through the rate design described earlier). Although it is likely that the larger customers would have significant seasonality in practice, perhaps beyond the underlying seasonality of the total block usage, this is immaterial to our illustrative example. Instead, the case study looks at the monthly bills and relative impacts of decoupling for a customer who uses the stated amount of energy in that month. Thus, the analysis is not one of a typical customer, but what a customer experiences in a given month at a particular usage level. Average usage was derived by dividing total annual usage by the number of customers and by 12.

Average Use Customers

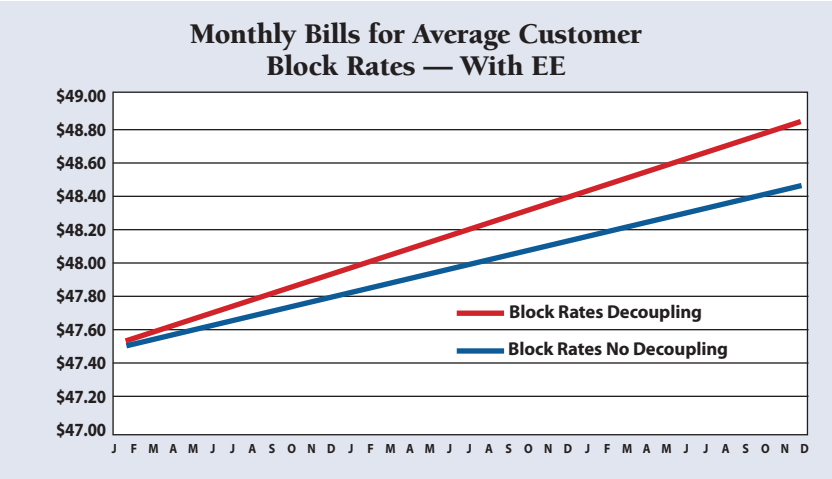
Business as Usual Bills

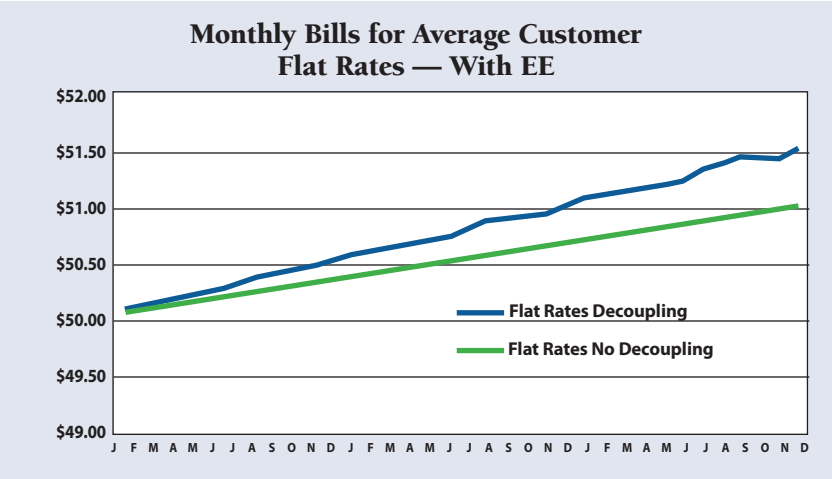
Each of these rate designs has a different impact on different types of users. For example, an "average" customer using 617 kWh in every month would see the bills shown at right before decoupling and without any energy efficiency savings. Note that SFV rates impose a minimum bill significantly higher than that imposed by either block or flat rates. That said, for an average customer, SFV rates produce bills comparable to flat rates. This is because the flat rate case and the SFV are both applied across all usage and this example is for an average customer. For block rates, usage level determines which rates are used for the same amount of usage. SFV rates are, in effect, average rates for average customers, so an average user pays nearly the same with SFV rates as with flat rates. Small users would be adversely impacted by SFV rates, and large users would benefit.



Customers Who Reduce Usage

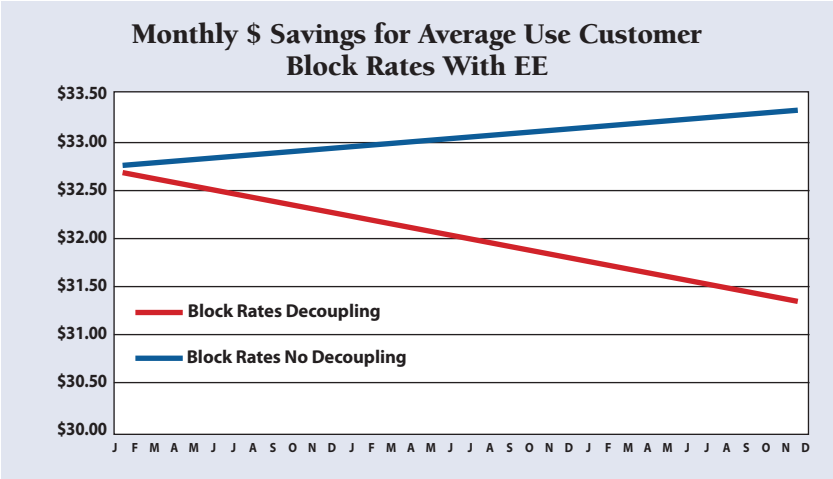
If we assume the same customer deploys sufficient energy efficiency to reduce consumption by 20% per month, bills will be as shown in the two charts below for block rates and flat rates. Monthly average differences associated with decoupling over the three-year period are $1.22 for block rates and $1.37 for flat rates. SFV with decoupling is not shown because decoupling has no effect on SFV bills. Block rates for this level of usage result in a blended effective energy price less than the flat rate. As a result, block rate bills are roughly $2.50 per month lower than for flat rates.

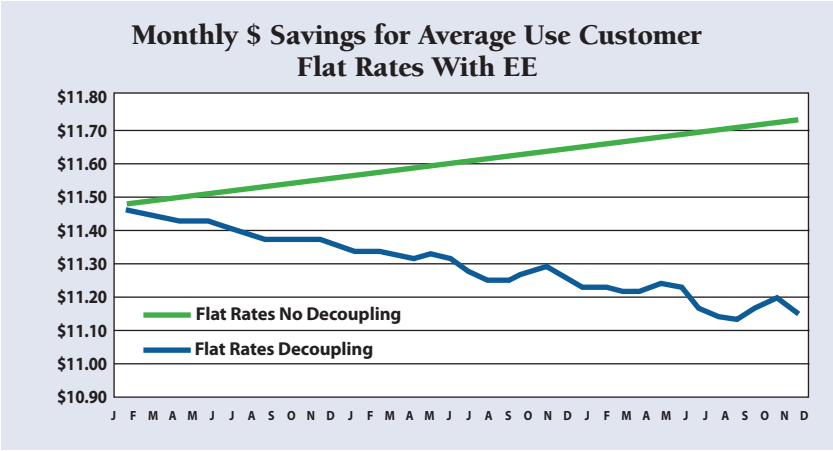




Monthly Savings

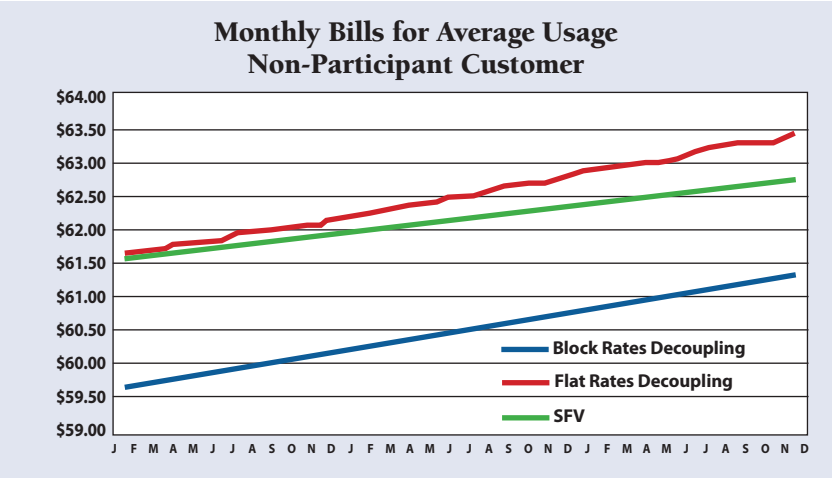
The associated monthly bill savings for the customer with a 20% reduction in consumption is shown in the two charts at right. The declining monthly benefits under both rate designs represent the erosion in savings occasioned by decoupling price adjustments. Block rate customers experience a $9 reduction in savings by the end of the study period, while flat rate customers experience a $3.00 reduction. Monthly savings for SFV customers (not shown) is limited to avoided fuel costs with inflation and reach $2.72 by the end of the study period.





Customers Who Do Not Reduce Usage

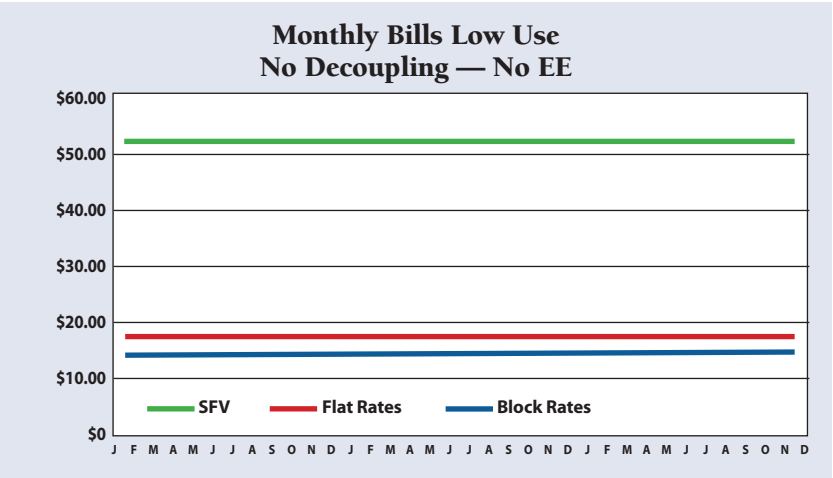
Bills for the average customer who does not reduce usage are shown at right. Because they are both versions of an average rate, flat rate and block rate customers experience an average of $1.60, while flat rate customers experience a $1.71 average increase in bills by the end of the study period. SFV customers only experience fuel inflation of $1.14 over the study period.



Low Usage Customers

Business as Usual Bills

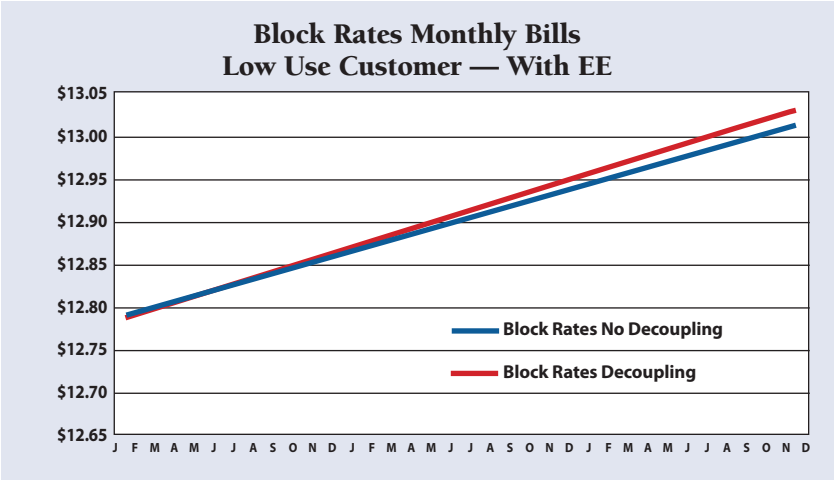
The low usage customer is assumed to consume 150 kWh each month of the year. As expected and except for SFV rates, low usage customers have

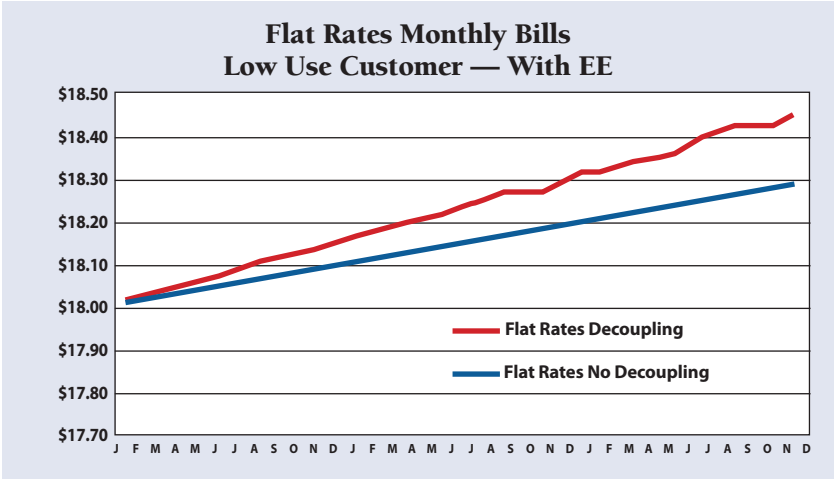


bills that are much lower than average customers. Without decoupling, all customers only experience an increase in bills from inflation in fuel costs of $0.28 each over the study period.

Customers Who Reduce Usage

Bills for a customer who reduces usage by 20% (30 kWh) are shown in the charts at right. For block rate bills, because most of the assumed energy savings occur in Block 3 and Block 2, virtually no decoupling adjustments show up in low use bills. As a result, bills for low usage customers with block rates are very stable.

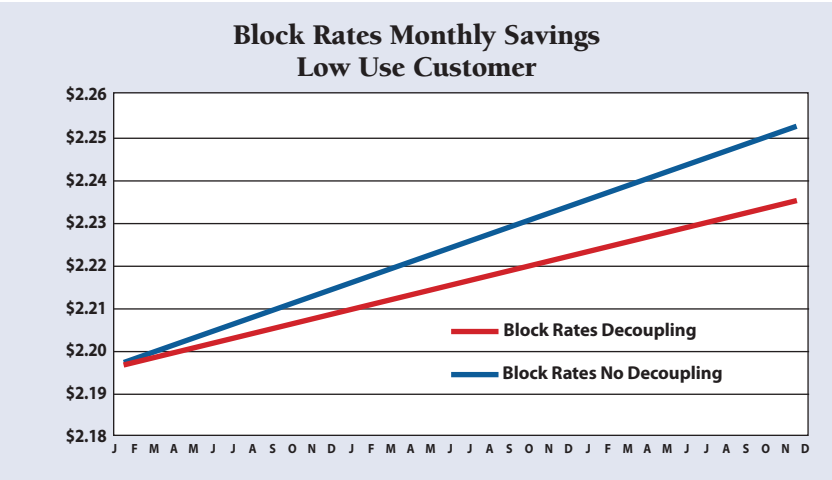


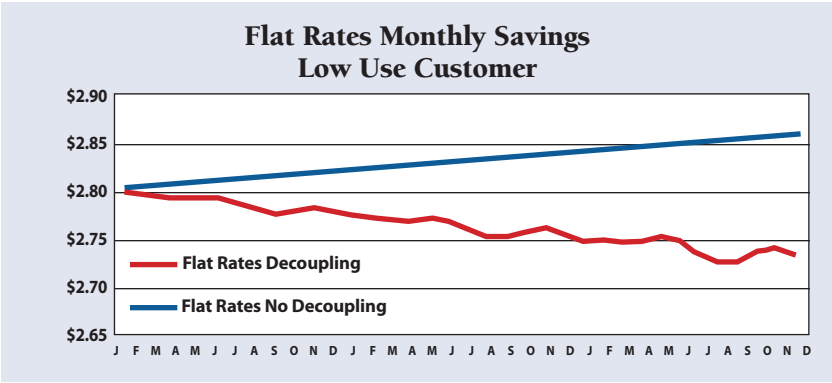


In the case of flat rate, because a uniform decoupling adjustment is applied to all consumption, low use customers experience an increase of approximately $1.20 per month by the end of the study period.

Monthly Savings

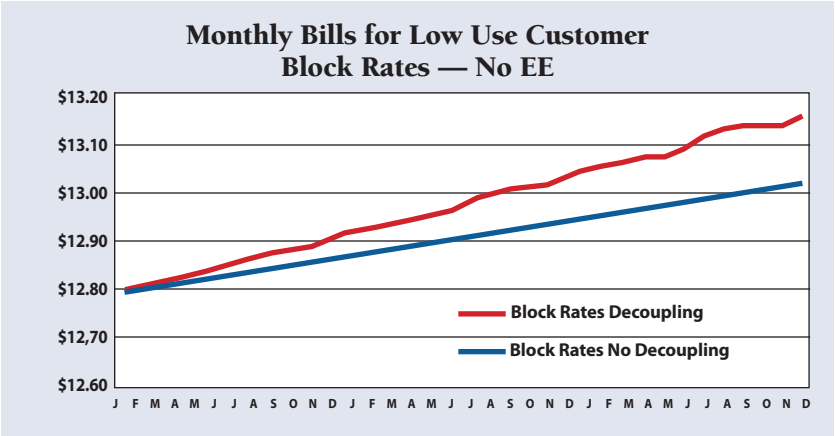
For customers who reduce usage by 20%, the monthly savings before and after decoupling are shown at right. SFV is ignored, because the only savings for an SFV customer is through the fuel clause. In this case, SFV fuel savings average $0.61 per month. With the assumed demand-side reductions in sales, pre-decoupling revenues are declining every month, so the decoupling adjustment has the effect of slightly eroding savings over time, though not by a material amount, reaching $0.39 and $0.64 per month for block and flat rates, respectively.

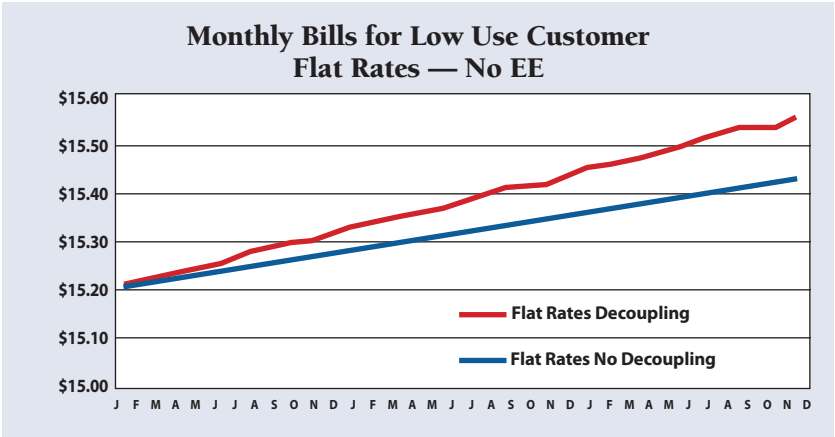




Low Use Customers Who Do Not Reduce Usage

The impact of decoupling on bills for customers who do not reduce usage is shown at right. Because very little of the revenue shortfall occurs in the first block, block rate customers do not see much impact from decoupling, with the maximum monthly impact occurring at the end of the study period at $0.03. Flat rate customers see a slightly greater impact, reaching $0.74 by the end of the study period.

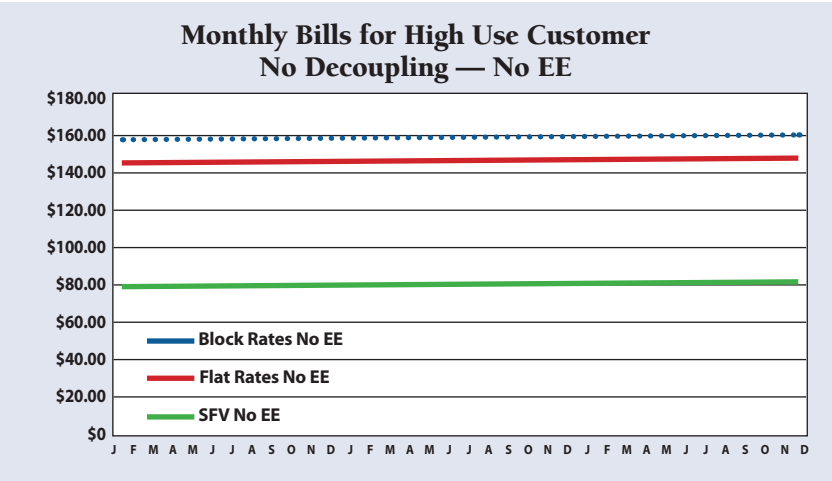




Impact of Decoupling on High Usage Customers

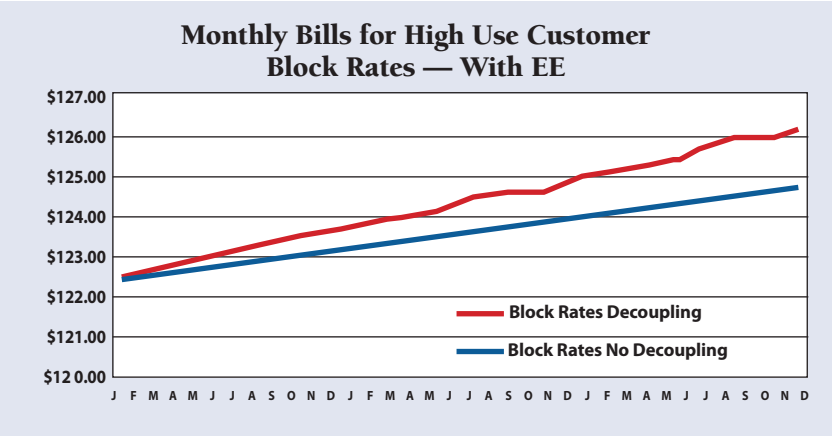
Business as Usual Bills

Business as usual bills for high usage customers are shown below. Because of the fixed nature of SFV rates, bills are much lower for high usage customers than with either block or flat rates.



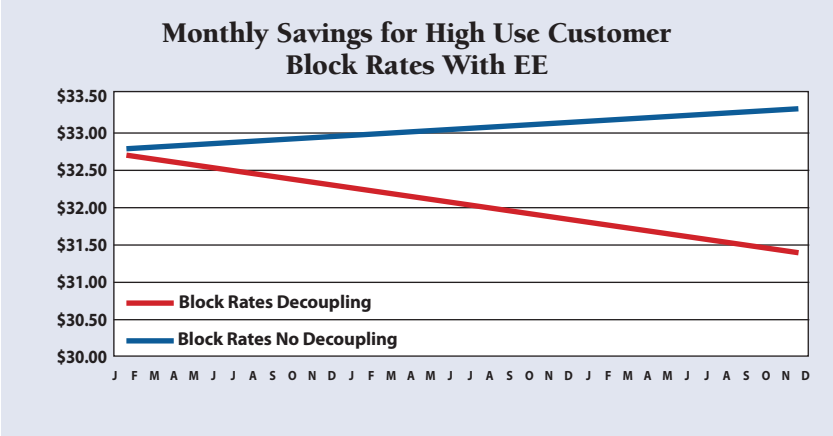
Customers Who Reduce Usage

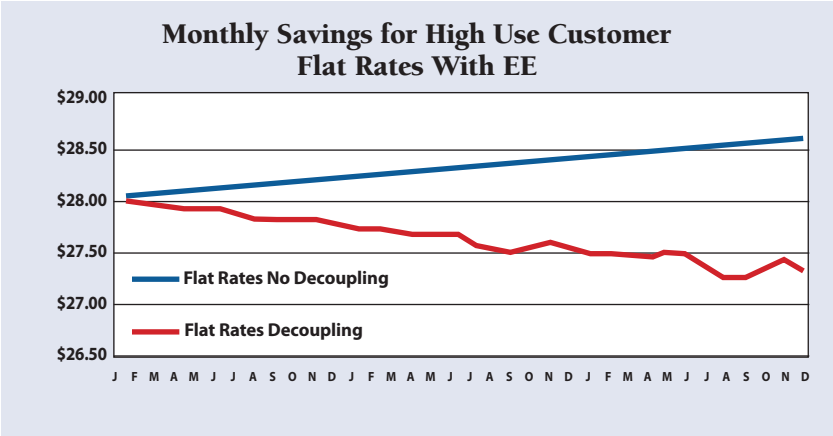
Bills for customers who reduce usage are shown below. Once again, rate design does not make a significant difference. For block rate customers, decoupling has an average monthly impact on savings of $3.95, and flat rates customers see $3.33 average monthly impact.



Monthly Savings

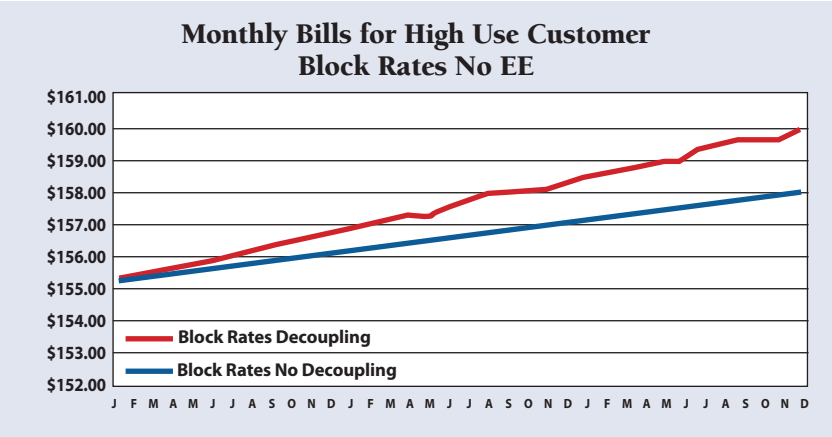
Monthly savings for customers who reduce usage are shown below. For block rate customers, because most of the demand-side reductions come from the tail block, most of the decoupling adjustments are recovered through that block. This concentrates the decoupling effect on large users. In this manner, smallusers with stable usage are essentially unaffected by decoupling rate adjustments. This has the same effect as expressed earlier in the bill comparison, translated into savings from energy efficiency as opposed to total bills.

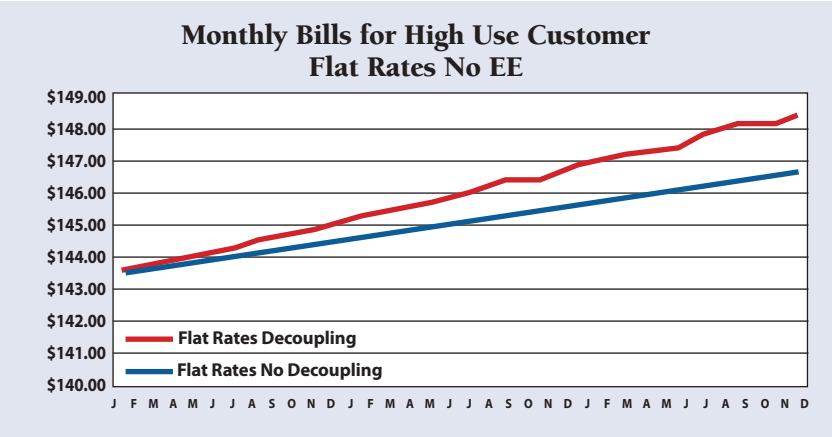




High Use Customers Who Do Not Reduce Usage

Bills for customers who do not reduce usage are shown below. Monthly average bill increases attributable to decoupling are $4.26 for block rate customers and $4.16 for flat rate customers.

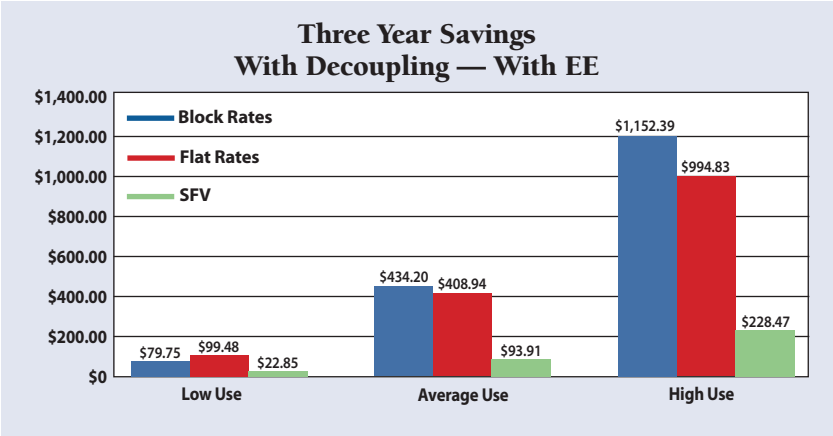




Three-Year Summary of Different Rate Designs

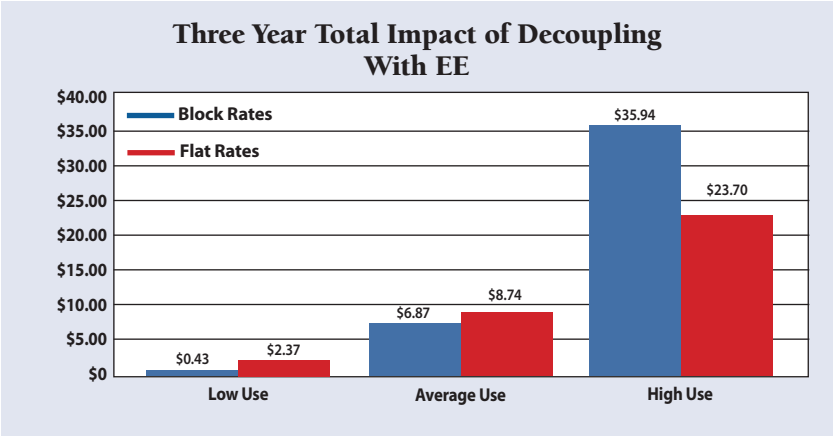
Three-Year Savings

This chart reflects the three-year savings for each type of customer for the three different rate designs. As usage grows, the savings increase accordingly. SFV rates limit savings to fuel costs only, however, resulting in significantly lower customer savings.



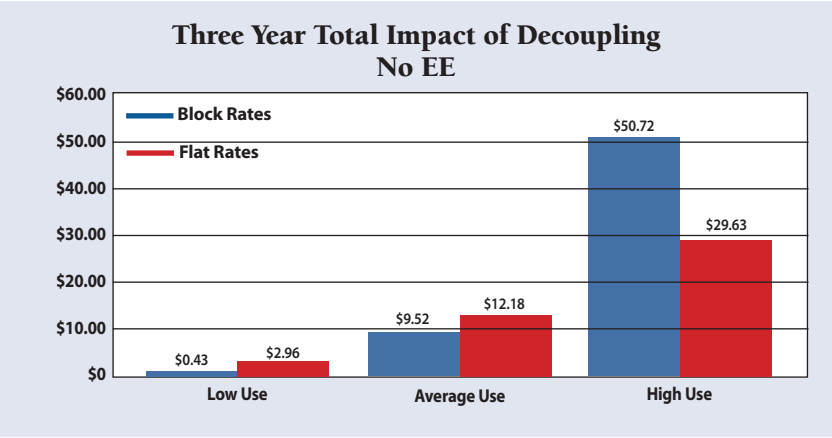
Impact of Decoupling for Customers With Energy Efficiency

The next chart reflects the impact of decoupling on the three types of customers with block and flat rates. SFV has no decoupling effect and is excluded.



Impact of Decoupling for Customers Who Do Not Implement Energy Efficiency

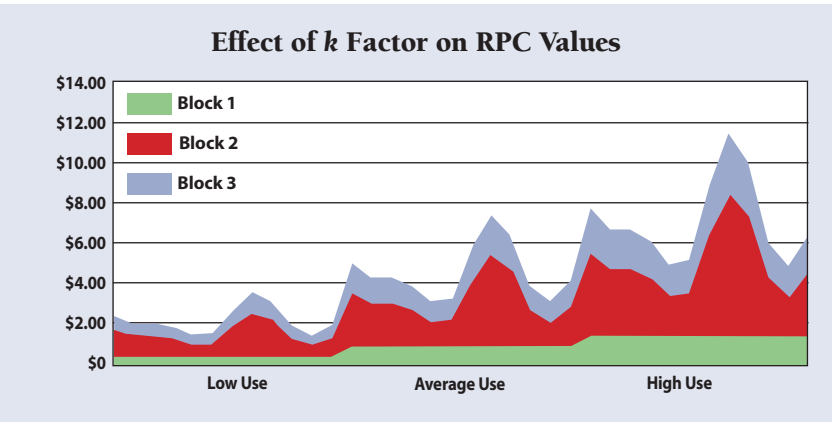
Finally, the chart below reflects the impact of decoupling on customers with no energy efficiency, often referred to as non-participants.



Effects of a k Factor

Applying a *k* Factor To RPC Values

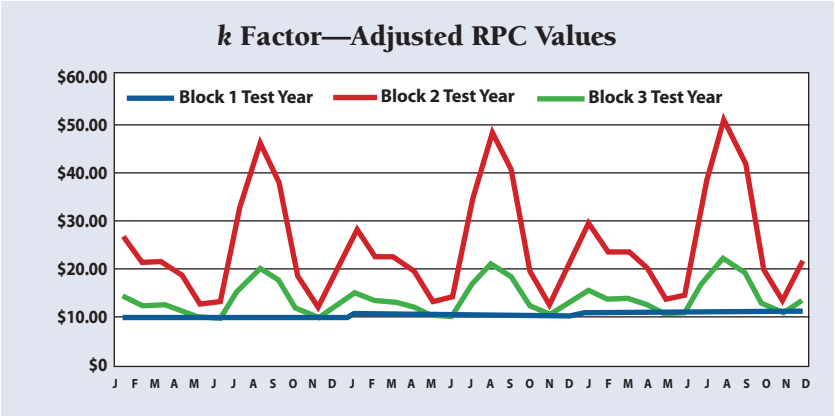
A *k* factor can be applied to the RPC values in decoupling to induce a "slope" (up or down) over time. A *k* factor would most likely be used as a proxy for inflation or other trends in underlying costs that are not captured by the core RPC values. For example, the impact of a 5% annual upward *k* factor on RPC values is shown at right. A slight upward slope can be seen for



each month over the prior year's month (and 5% is clearly higher than recent inflation rates and was chosen to illustrate the effect of an allowed upward attrition adjustment over time). Because the first block is assumed to have zero weather sensitivity, it "steps" up over time, rather than following seasonal patterns.

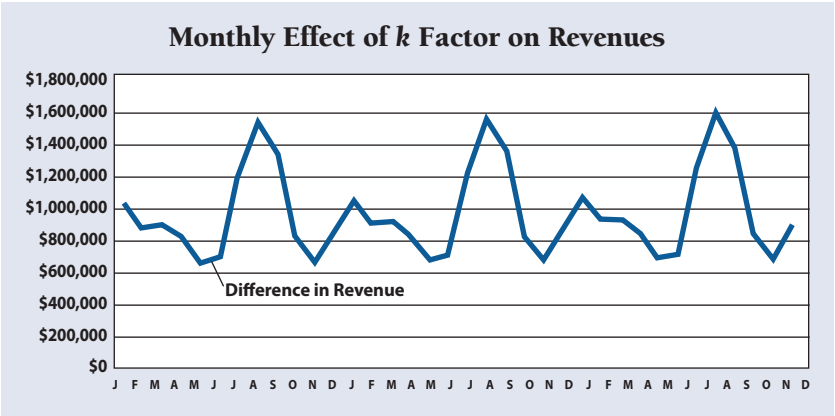
Impact of a *k* Factor on RPC Values

The *k* factor is applied to each RPC value. The resulting increase in the RPC for each block rate is shown below. Most of the revenues come from Block 2, which experiences the greatest growth over time.



Monthly Effect of a *k* Factor

The revenue impact of the *k* factor is shown below. In this case, it has the effect of adding approximately $650,000 to $1.3 million per month to



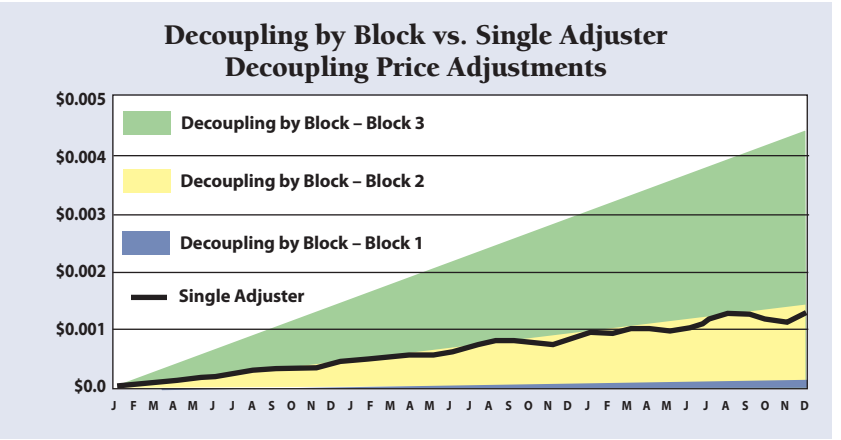
total revenues, or slightly more than 4.5% of total non-fuel revenues. This hypothetical k factor represents, for example, the effect of an assumption of increased costs over time due to inflation, replacement of non-revenue-producing infrastructure, and increasing costs associated with environmental compliance.

Decoupling by Block Method vs. Single Adjuster Method

In a block rate environment, revenue differences are inherently driven by the individual revenue increases or decreases in each block. In a Decoupling by Block Method, modeled below, each individual block price is adjusted to correct for revenue deviations. As an alternative, a single (in effect, average) decoupling price can be computed and added to all blocks. This is termed a Single Adjuster Method. Another method, proposed by Tucson Electric Power (TEP) in Arizona, is to apply any decoupling surcharges to the upper blocks of usage, and any decoupling surcredits to the initial block of usage, thereby ensuring that low-users are never harmed by decoupling, and high-users are never advantaged by increased usage. We have not modeled this approach.

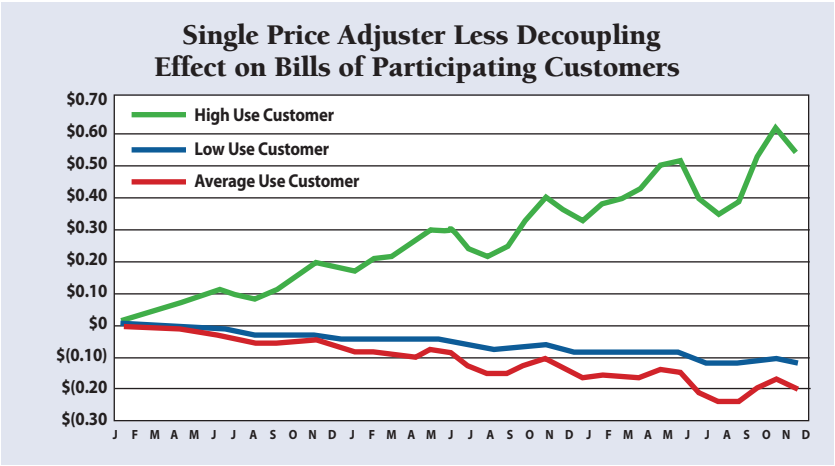
Decoupling Price Adjustments

The chart at right displays the price increases for each block in the Decoupling by Block Method (shaded areas) and the equivalent Single Adjuster (line). Because most of the demand-side reductions are assumed to come from Block 3, that block receives the lion's share of the decoupling price adjustments. Low usage customers have their consumption concentrated in the first block, which sees hardly any adjustment at all with the Block Method, but with the Single Adjuster Method they see the same increase in prices as all other customers.



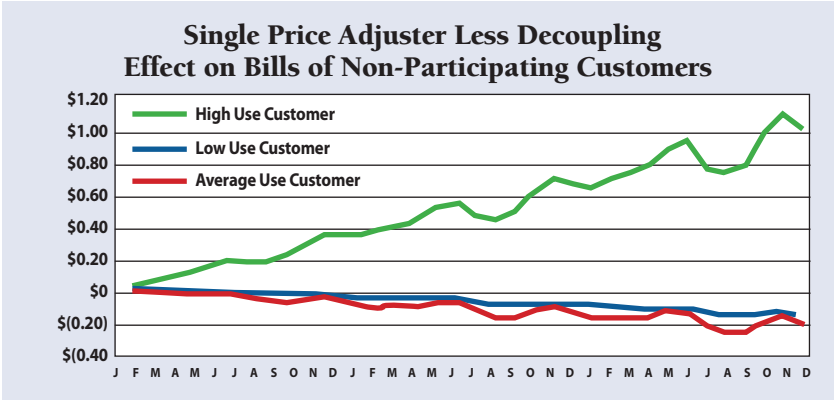
Impact on Bills of Customers Who Reduce Usage

The impact of the Single Adjuster Method versus the Decoupling by Block Method is shown below. Low energy users and average energy users experience an increase in bills of up to $0.13 (low) and $0.23 (average) per month, whereas high usage customers experience decreases in bills of up to $0.59 per month. In effect, the Single Adjuster Method mitigates the rate design impact of inclining block rates and reduces bills for large users at the expense of other users.



Impact on Bills of Customers Who Do Not Reduce Usage

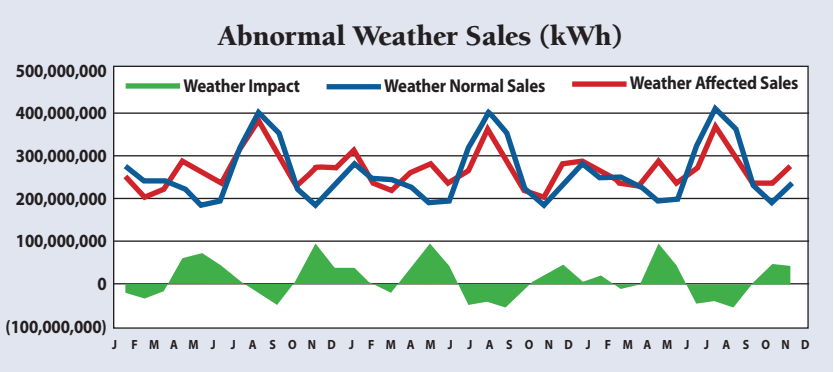
The impact of the Single Adjuster Method is shown below. For customers with greater usage, the impact is greater. Here the savings to high usage customers reaches $1.23 per month, again at the expense of low usage and average customers, who experience $0.16 (low) and $0.25 (average) per month increases.



Impact of Weather on Decoupling Adjustments

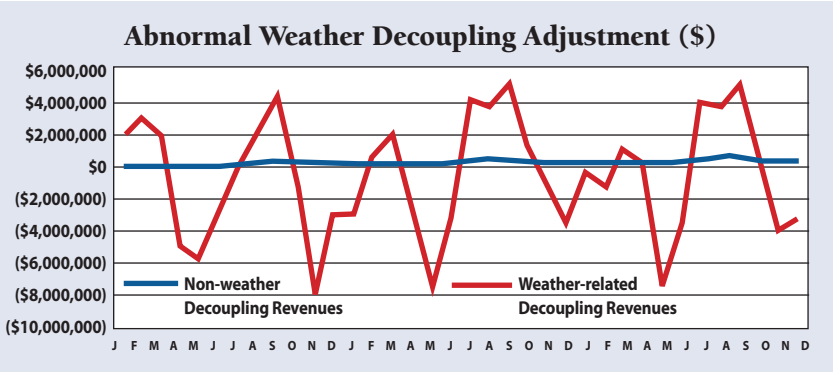
Sales Deviations Caused by Weather

Full decoupling eliminates the effects of weather on revenues. For our case study, we took a three-year period (2000-2002) that had the highest combined heating degree days (HDD) and cooling degree days (CDD) and modeled prototypical sales under these conditions. The chart below compares normal weather sales and our resulting "extreme" weather sales. The green "area" graph at the bottom reflects the increase or decrease in sales associated with the HDD and CDD for the three-year period. Changes in sales range from an increase of approximately 55 million kWh to a decrease of approximately 60 million kWh.



Weather-related Decoupling Revenue Adjustments

The case study assumes that the changes in revenues from non-normal weather affect Blocks 1 and 2 in the same proportion as that associated with normal weather. The chart below shows the revenue impacts from abnormal weather and, separately, the revenue impacts from demand-side reductions

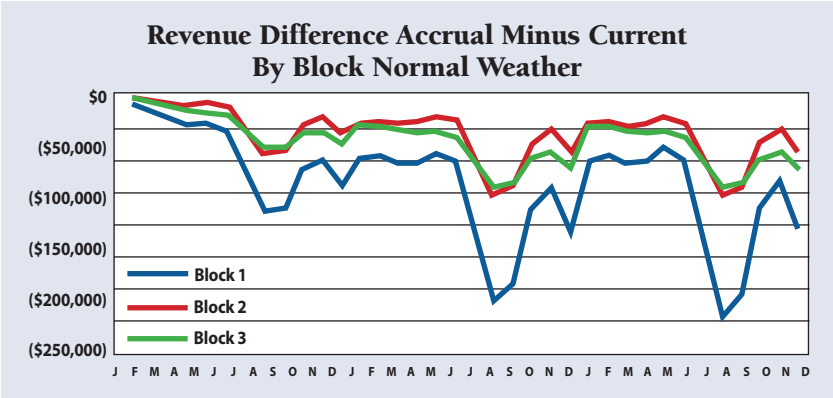


(non-weather related changes). Weather is, by far, the greatest volatility risk for consumers, whereas the balance of the decoupling adjustment is miniscule. At the same time, changes in bills and revenues from weather risk are eliminated by full decoupling. During the three-year period, the maximum shortfall in revenues is approximately $4.7 million and the maximum is approximately $5 million.

Impact of Accrual versus Annual Method

Revenue Difference of Current and Accrual Methods With Normal Weather

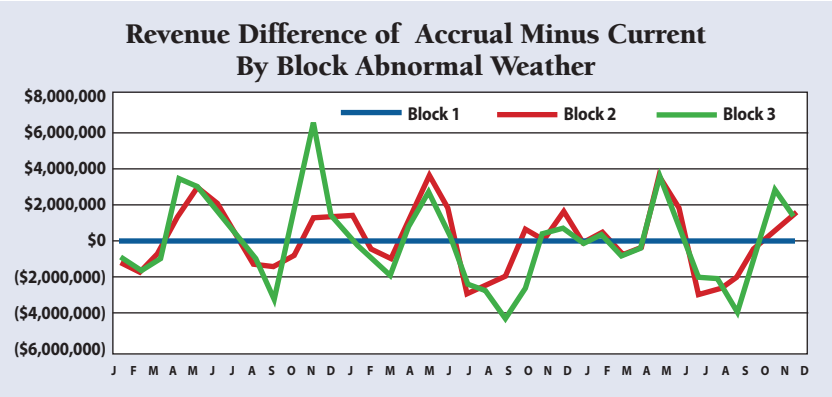
In all of the previous analyses, the indicated decoupling adjustment has been applied in the month during which it occurs, a method we term the Accrual Method. However, many states have applied an Accrual Method, usually with a one-year lag. This chart shows the impact on each block rate of using the Annual Method instead of the Accrual Method in normal weather conditions. Because of the lag imposed by the Accrual Method, the relationship between the decoupling adjustment and the underlying consumption that caused the adjustment is shifted by one year, resulting in a steadily increasing downward impact on revenues in all three blocks.



Revenue Difference of Current and Accrual Methods With Abnormal Weather

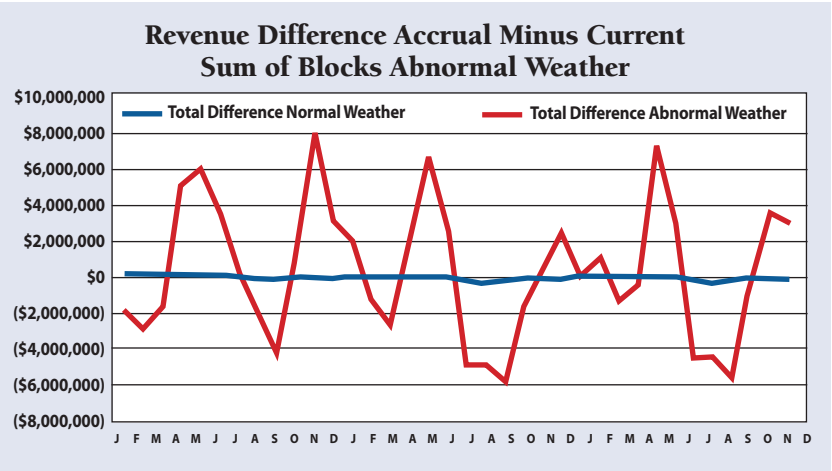
The next chart reflects the same impact on revenues for each block in the abnormal weather case. As can be seen, the occurrence of abnormal weather has the effect of imposing much greater volatility on total revenues. In effect, the relationship between the decoupling adjustment and the underlying consumption patterns that cause the decoupling adjustment is completely

lost, and the underlying lag caused by the annual method is overwhelmed by the effects of weather.



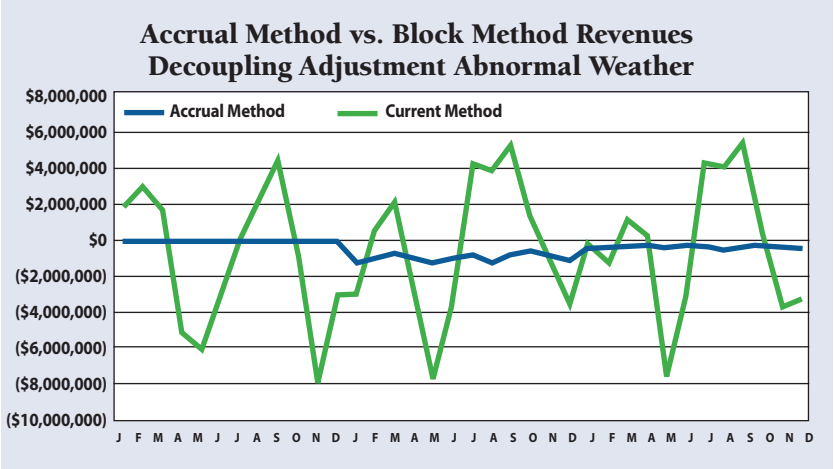
Accrual vs. Current Difference Revenues – Impact of Abnormal Weather

The chart below reflects the differences in abnormal weather conditions occasioned by the use of the Annual Method versus the Accrual Method. As can be seen, the normal weather results in small differences between the Accrual and Current methods, whereas abnormal weather results in significant departure. This chart reflects the disconnect between decoupling adjustments and the underlying cause for those adjustments with the Accrual Method.



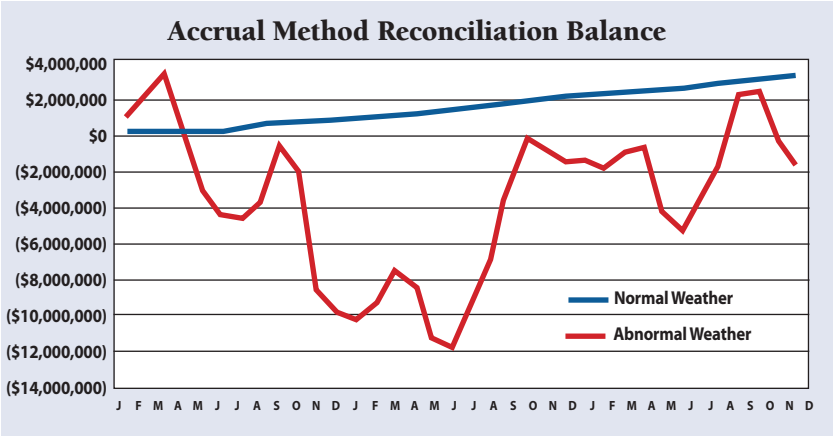
Accrual vs. Current Decoupling Adjustment Revenues With Abnormal Weather

The next chart reflects the differences in the Current and Accrual methods in periods of abnormal weather. The Current Method reflects the adjustment associated with abnormal weather for the associated period. The Accrual Method has no direct relationship to the current period weather. The difference between the two reflects the amount by which the Accrual Method fails to match up to the adjustment caused in the associated period.



Accrual Reconciliation Balance – Normal vs. Abnormal Weather

The final chart reflects the Reconciliation Balance Account during normal weather and abnormal weather. In normal weather conditions, there is a



steady increase in the balancing account caused by the lag in collection and the underlying growth in customers and consumption. This effect essentially disappears in abnormal weather conditions, when consumption varies significantly, both up and down, relative to normal weather consumption.

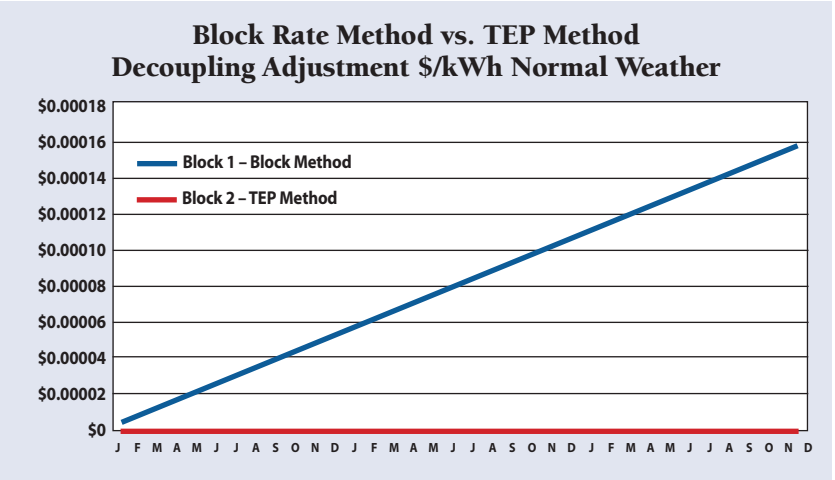
The Tucson Electric Power Decoupling Method

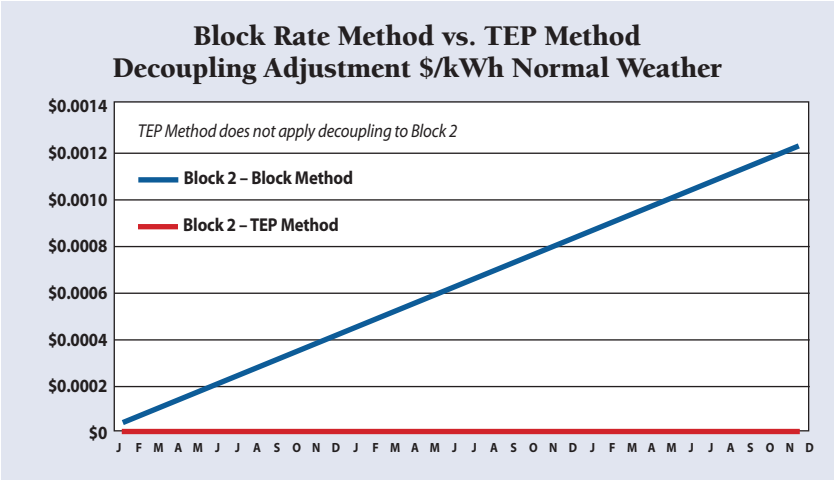
In decoupling workshops held by the Arizona Corporation Commission, Tucson Electric Power (TEP) proposed a method of decoupling in which all surcharges would be applied to the tail block in a block rate design and credits would be applied to the first block. We have modeled this method for both normal and abnormal weather conditions with the following results.

Decoupling Adjustments By Block — Normal Weather

The chart at right reflects the decoupling adjustment for Block 1 for both the block rates method and the TEP method. Because normal weather resulted in a positive decoupling adjustment in every period, there are no adjustments to this block using the TEP method. We omit Block 2, because the TEP method never makes adjustments to this block.

The next chart reflects the decoupling adjustment for Block 3, comparing the normal block method with the TEP method. For the TEP method, Block 3 receives all of the adjustments in normal weather conditions.

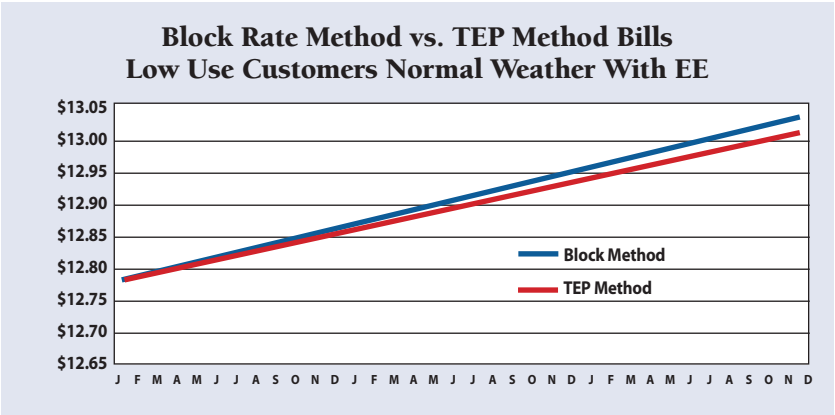




Impact of the Tucson Electric Power Method on Bills of Customers — Reduced Usage — Normal Weather

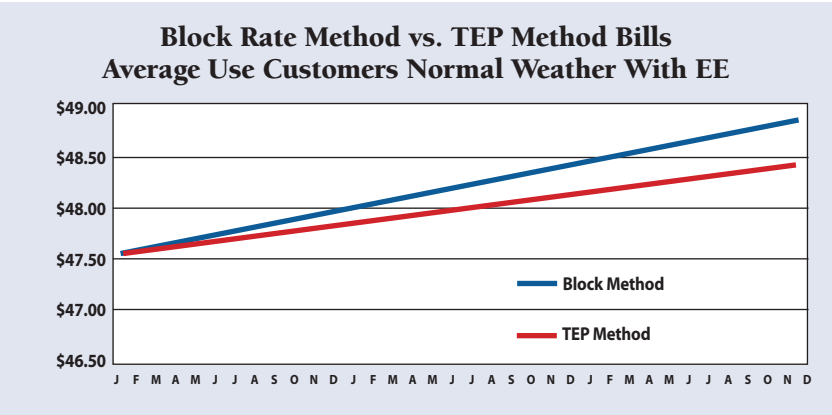
Low Use Customers

As in the next chart, the TEP method has the effect of lowering bills for low use customers, all of whose usage is in the first block. This is because when the adjustment is positive, it is not applied to the first block, while the normal block rate method adjusts each block according to its contribution to the overall surcharge or credit. Low use customers receive an average $0.19 reduction in monthly bills, reaching a maximum of $0.39 savings by the end of the study period.



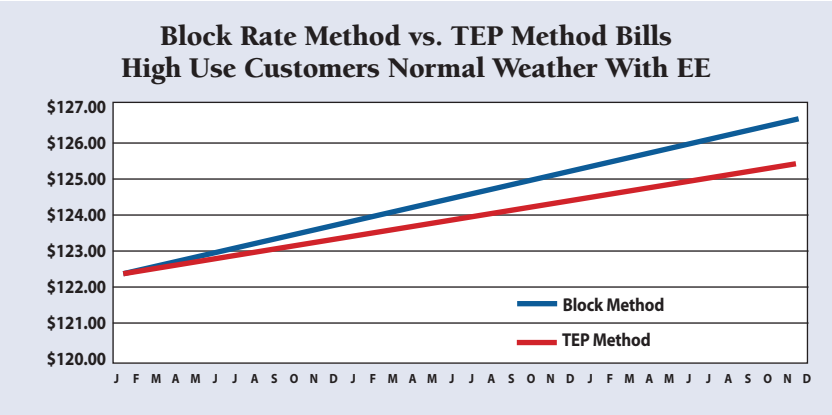
Average Use Customers

For average use customers, the TEP method has the effect of decreasing bills, as well. This is because in normal weather conditions, all of the decoupling adjustments are positive and the TEP method makes no adjustments to Block 2. Average use customers enjoy average monthly savings of $1.22 per month, reaching a maximum of $2.63 in savings by the end of the study period.



High Use Customers

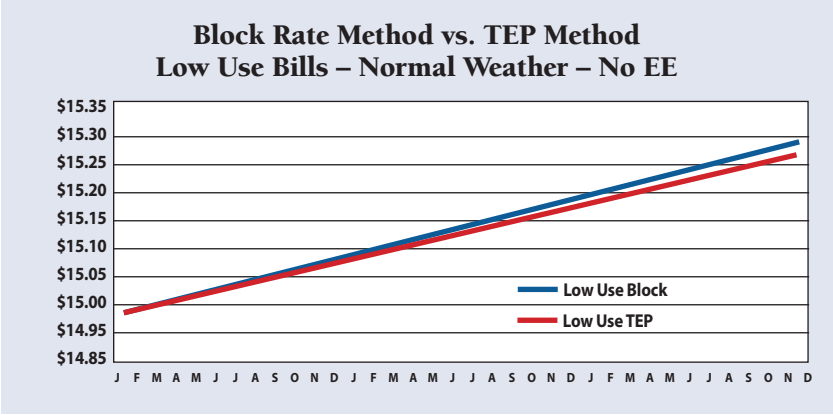
For high use customers, the results are quite different. For these customers, whose usage reaches the tail block, the positive decoupling adjustments during normal weather are exclusively applied to these customers. For high use customers, the average monthly increase in bills is $2.10, reaching a maximum of $4.60 by the end of the study period.



Impact of the Tucson Electric Power Method on Bills of Customers – No Reduced Usage – Normal Weather

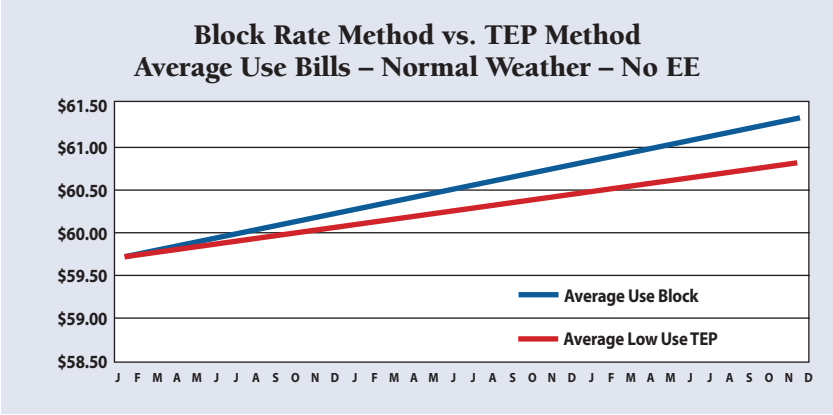
Low Use Customers

Low use customers who do not employ energy efficiency or otherwise reduce usage enjoy a slightly higher level of savings with the TEP method than with the normal block rate method. For these customers, the average monthly decrease in bills in normal weather conditions is $0.24, reaching a maximum of $0.49 by the end of the study period.



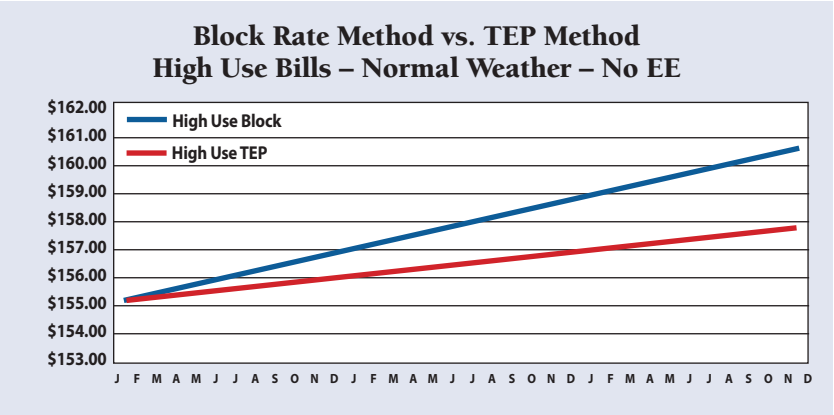
Average Use Customers

Non-participant average use customers also enjoy a reduction in bills with the TEP method. For these customers, the monthly average savings over the study period is $1.60, reaching a maximum of $3.47 by the end of the study period.



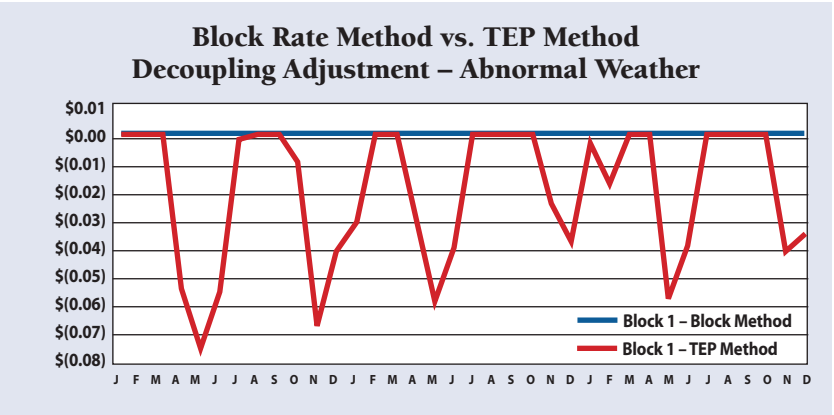
High Use Customers

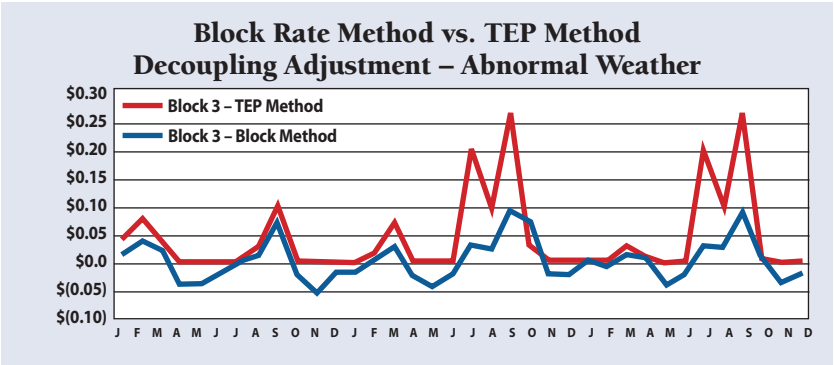
Non-participant high use customers receive an increase in bills with the TEP method. For these customers, the average monthly increase in bills is $4.47 per month, reaching a maximum of $9.78 by the end of the study period.



Decoupling Adjustments By Block – Abnormal Weather

Under abnormal weather conditions, the impacts of the TEP method on the different types of users can be more pronounced and more variable than under normal weather conditions. The chart at right shows the decoupling adjustments applied to low use customers, all of whose usage is in the first block. Because the TEP method only allows negative decoupling adjustments to be applied to the first block, the TEP adjustments are either negative or zero. The average monthly difference versus the regular block rate method is approximately $0.02, with a maximum difference of approximately $0.075.





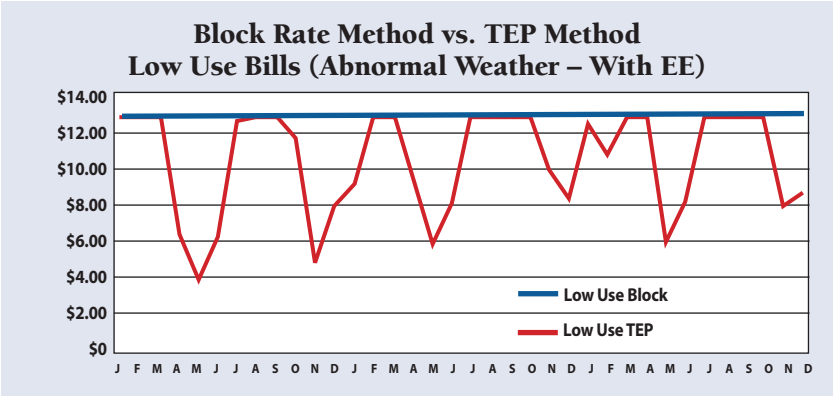
Once again, we omit the Block 2 analysis, because the TEP method is never applied to Block 2.

The Block 3 decoupling adjustments also exhibit greater magnitude and variability under abnormal weather conditions. The average decoupling adjustment for Block 3 is $0.05, whereas the maximum adjustment is approximately $0.28.

Impact of the Tucson Electric Power Method on Bills of Customers – Reduced Usage – Abnormal Weather

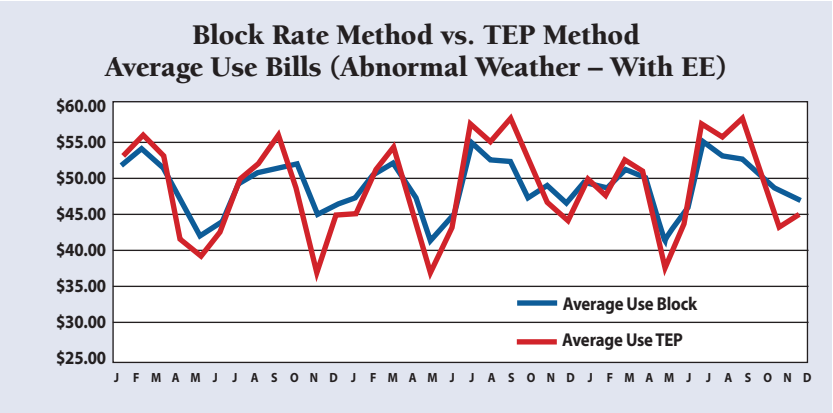
Low Use Customers

The chart below reflects the monthly bills for low use customers for the normal block rate method and the TEP methods under abnormal weather conditions. While the block rate method results in a fairly steady increase over time, the bills for the TEP method vary from as low as $12.34 and as high as $13.00, with an average of $12.79.



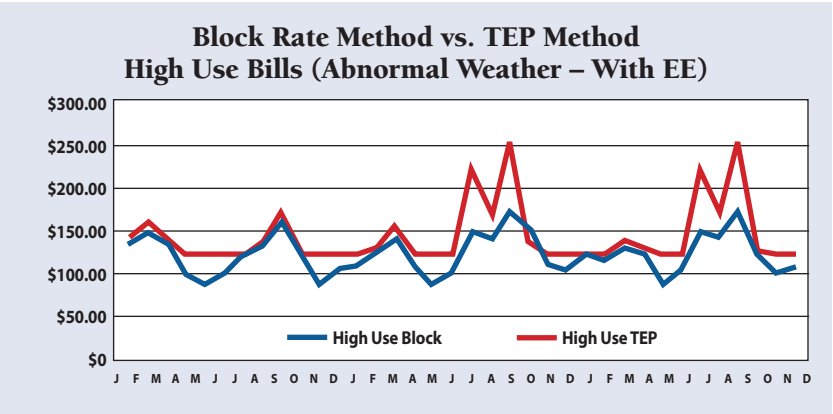
Average Use Customers

For average use customers, the difference between the block rate method and the TEP method is caused by the absence of any decoupling adjustment in the TEP method. The average bill with the block rate method is $48.01, with a minimum of $38.67 and a maximum of $56.31. TEP bills average $47.83, just $0.18 different than with block rates, with a minimum of $33.89 and a maximum of $60.67.



High Use Customers

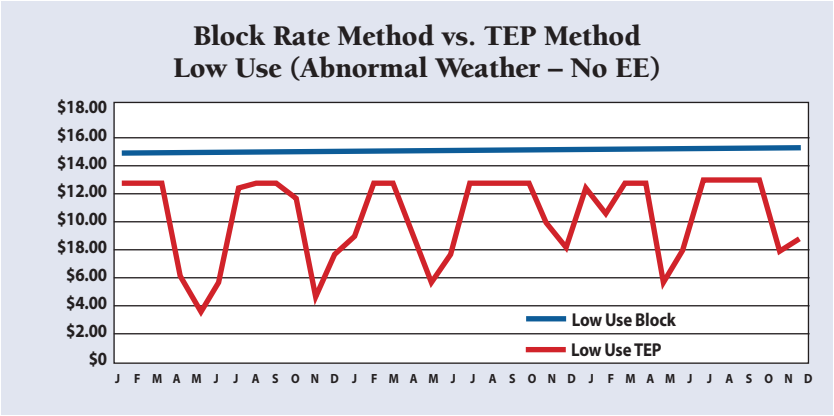
For high use customers, the TEP method results in bills that are mostly higher and occasionally approximately the same as with the block rate method. Block rates result in an average bill of $126.19, with a minimum of $86.28 and a maximum of $320.09.



Impact of the Tucson Electric Power Method on Bills of Customers – No Reduced Usage – Abnormal Weather

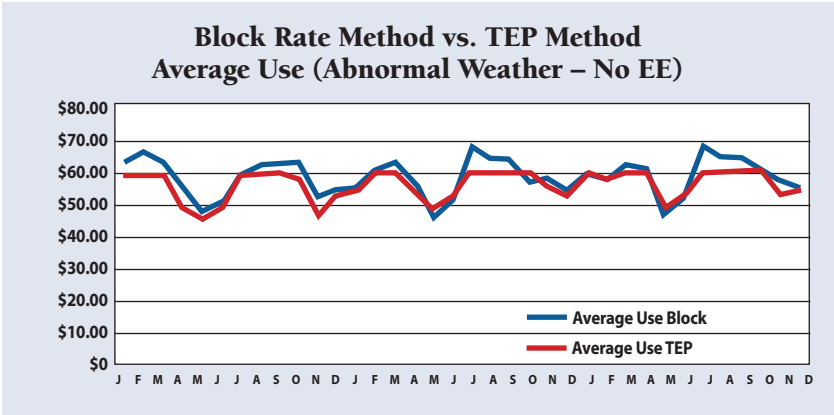
Low Use Customers

This graph shows the effect of using the TEP methodology under abnormal weather for low use customers.



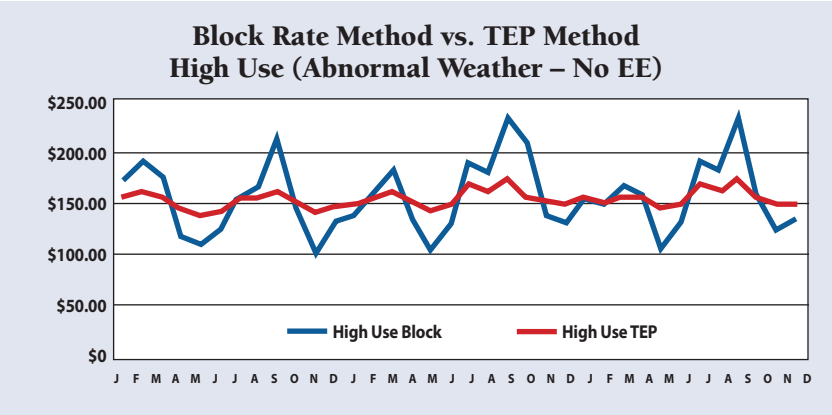
Average Use Customers

This graph shows the effect of using the TEP methodology under abnormal weather for average use customers.



High Use Customers

This graph shows the effect of using the TEP methodology under abnormal weather for high use customers.



Marcus - Attachment D

FORM A

Proceeding: EB-2012-0410

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is William B. Marcus. I live at Woodland, in the state of California .

2. I have been engaged by or on behalf of Green Energy Coalition to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
   (a) to provide opinion evidence that is fair, objective and non-partisan;
   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date June 1, 2014

Signature

William B. Marcus

Principal Economist,
JBS Energy, Inc.

William B. Marcus has 35 years of experience in analyzing electric and gas utilities.

Mr. Marcus graduated from Harvard College with an A.B. magna cum laude in economics in 1974 and was elected to Phi Beta Kappa. In 1975, he received an M.A. in economics from the University of Toronto.

In July, 1984, Mr. Marcus became Principal Economist for JBS Energy, Inc. In this position, he is the company's lead economist for utility issues.

Mr. Marcus is the co-author of a book on electric restructuring prepared for the National Association of Regulatory Utility Commissioners. He wrote a major report on Performance Based Ratemaking for the Energy Foundation.

Mr. Marcus has prepared testimony and formal comments submitted to the Federal Energy Regulatory Commission, the National Energy Board of Canada, the Bonneville Power Administration, the U.S. Bureau of Indian Affairs, U.S. District Court in San Diego, Nevada County Municipal Court; committees of the Nevada, Ontario and California legislatures and the Los Angeles City Council; the California Energy Commission (CEC), the Sacramento Municipal Utility District (SMUD), the Transmission Agency of Northern California, the State of Nevada's Colorado River Commission, a hearing panel of the Alberta Beverage Container Management Board; two arbitration cases, environmental boards in Ontario, Manitoba, and Nova Scotia; and regulatory commissions in Alberta, Arizona, Arkansas, British Columbia, California, Colorado, Connecticut, District of Columbia, Hawaii, Iowa, Manitoba, Maryland, Massachusetts, Nebraska, Nevada, New Jersey, New Mexico, North Carolina, Northwest Territories, Nova Scotia, Ohio, Oklahoma, Ontario, Oregon, South Carolina, Texas, Utah, Vermont, Virginia, Washington, Wisconsin, and Yukon. He testified on issues including utility restructuring, stranded costs, Performance-Based Ratemaking, resource planning, load forecasts, need for powerplants and transmission lines, environmental effects of electricity production, evaluation of conservation potential and programs, utility affiliate transactions, mergers, utility revenue requirements, avoided cost, and electric and gas cost of service and rate design.

From July, 1978 through April, 1982, Mr. Marcus was an economist at the CEC, first in the energy development division and later as a senior economist in the CEC's Executive Office. He prepared testimony on purchased power pricing and economic studies of transmission projects, renewable resources, and conservation programs, and managed interventions in utility rate cases.

From April, 1982, through June, 1984, he was principal economist at California Hydro Systems, Inc., an alternative energy consulting and development company. He prepared financial analyses of projects, negotiated utility contracts, and provided consulting services on utility economics.

PUBLICATIONS

W. Marcus and C. Mitchell, "Critical Thinking on California IOU Energy Efficiency Performance Incentives from a Consumer Advocate's Perspective," Proceedings of 2006 ACEEE Summer Study on Energy Efficiency in Buildings, Panel 5, August 18, 2006.

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Author or co-author of eight cases published by the Kennedy School of Government, Harvard University, and the Inter-University Case Clearinghouse.

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CPUC Application 10-11-015. Policy and Revenue Requirements Issues in SCE's 2011 Test Year General Rate Case. June 2011. For TURN.

CPUC Application 10-11-009. Revenue Requirements for SCE's Catalina Island Water Utility. May 2011. For TURN.

Alberta Utilities Commission (AUC) Application 1606549. Business Risk of Gas and Electric Utilities; Management Fees for Contributions in Aid of Construction. March 2011. For the Alberta Utilities Consumer Advocate (UCA).

Arkansas PSC Docket 10-067-U. Revenue Requirement, Cost of Service and Residential Rate Design for Oklahoma Gas and Electric Company (OG&E). March 2011. For the Arkansas AG (case settled).

PUCN. Dockets 10-10024 and 10-10025. Estimating Lost Revenue from Energy Efficiency for Sierra Pacific Power Company (Sierra) and Nevada Power Company (NPC). March 2011. For Nevada BCP.

CPUC App. 10-07-009. Policy Issues Related to Critical Peak Pricing for SDG&E. February 2011. For UCAN. (case settled)

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PUCT Docket 38480. Revenue Requirement, Cost of Service, and Residential Rate Design for Texas New Mexico Power Company (TNMP). November 2010. For the Texas OPUC. (case settled)

Colorado PUC. Docket No. 10AL-455G. Capital Structure and Rate of Return for Source Gas Distribution. October 2010. For AM Gas Transport Corp. and Barton Levin. (case settled)

PUCN Docket 10-06001 et al. Marginal Cost, Revenue Allocation, and Residential Rate Design for Sierra. October 2010. For Nevada BCP.

CPUC Application 10-03-014. Marginal Cost, Revenue Allocation, and Residential Rate Design for PG&E. October 2010. For TURN. (case settled, except residential rate design)

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Iowa Utilities Board. Docket No. RPU-2010-0001. Weather Normalization, Cost of Service and Residential Rate Design for Interstate Power Limited. July 2010. For the Iowa OCA.

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AUC Application No. 1605758. Return Margin for Epcor Energy Alberta, Inc. (EEAI) Electric Regulated Rate Tariff (RRT). June 2010. For Alberta UCA. (case settled)

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CPUC App. 09-12-002. Choice of Investment Tax Credit versus Production Tax Credit for PG&E's Proposal to Acquire the Manzana Wind Project. April 2010. For TURN.

Arkansas PSC Docket 10-008-U. Securitization of Ice Storm Costs for EAI. March 2010. For the Arkansas AG.

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PUCT Docket 37364. Construction Work in Progress in the Rate Base and other Revenue Requirement Issues for SWEPCO. February 2010. For Texas OPUC. (case settled)

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AUC Application 1587092. Cost Allocation and Rate Design for Atco Gas Ltd.. July 2009. For the Alberta UCA. (joint with H. VanderVeen and R. Bruggeman; case settled)

CPUC Application 08-05-023. PG&E's Distribution Reliability Improvement Program. July 2009. For TURN.

Arkansas PSC Docket 09-008-U. Construction Work in Progress in the Rate Base, Revenue Requirement, Cost of Service, and Residential Rate Design for SWEPCO. June 2009. For the Arkansas AG. (case settled)

PUCT. Docket 36025. Revenue Requirement and Hurricane Ike Cost Recovery for TNMP. For Texas OPUC. April 2009 (case settled).

PUCN. Docket 07-12005. Executive Compensation Request of Nevada Power Company (NPC). April 2009. For Nevada BCP.

AUC Application 1587092. Management Fee for Contributions in Aid of Construction for AltaLink Management. March 2009. For the Consumers' Coalition of Alberta (CCA) and Public Institutional Consumers of Alberta (PICA).

AUC Application 1578571. Business Risk of Alberta Utilities. March 2009. For the Alberta UCA.

Arkansas PSC Docket 08-103-U. Revenue Requirement, Cost of Service, and Residential Rate Design for OG&E. January 2009. For the Arkansas AG. (case settled)

CPUC App. 08-02-001 Phase 2. Cost of Service and Revenue Allocation for SoCal Gas. December 2008. For TURN. (case settled)

AUC Application No. 1578371. Management Fee for Contributions in Aid of Construction for Atco Electric Company. December 2008. For CCA and PICA.

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PUCT Docket 35717. Cost of Service and Rate Design for Oncor Delivery Services, Inc. For Texas OPUC. October 2008.

CPUC App. 08-03-002.Cost of Service and Class Revenue Allocation for SCE. October 2008. For TURN. (case settled)

PUCT Docket 35763. Revenue Requirements, Cost of Service, and Rate Design of Southwestern Public Service Company (SPS). For Texas OPUC. October 2008. (case settled)

PUCT Docket 35668. Interruptible Rates and Air Conditioner and Water Heater Cycling Programs of SPS. For Texas OPUC. September 2008. (case settled)

Colorado PUC, Docket 08S-146G. Cost Allocation and Rate Design for Public Service Company of Colorado's Gas Operations. For Energy Outreach Colorado. July 2008.

AUC Application No. 1512069. Evaluation of Ten-Year Formula Based Rate Program of Enmax Power Corporation. July 2008. For the CCA and PICA.

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Arkansas PSC Docket 06-152-U Phase IIB. Capacity Acquisition Rider for the Ouachita Plant of EAI. October 2007. For the Arkansas AG.

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Arkansas PSC Docket 07-129-U. Annual Earnings Review Tariff for EAI. October 2007. For the Arkansas AG.

Arkansas PSC Docket 06-152-U Phase IIA. EAI's Proposed Capacity Acquisition Rider. October 2007. For the Arkansas AG.

Arkansas PSC Docket 07-026-U. Revenue Requirement, Cost of Service, and Residential Rate Design for Arkansas Oklahoma Gas Corporation (AOG). September 2007. For the Arkansas AG. (case settled)

CPUC App. 07-01-041. Marginal Cost and Revenue Allocation for SDG&E. August 2007. For UCAN. (case settled)

CPUC App. 07-05-003 et al. Pension and Decommissioning Fund Returns as Related to Cost of Capital of California Energy Utilities. August 2007. For Aglet Consumer Alliance (Aglet), TURN, and UCAN.

Arkansas PSC Docket 06-161-U. Revenue Requirement and Cost of Service for Centerpoint Arkla. July 2007. For the Arkansas AG. (case settled)

CPUC App. 06-12-009/010. Revenue Requirements Issues for SoCal Gas and SDG&E. July 2007. For TURN (SoCal Gas) and UCAN (SDG&E). (SoCal Gas portion of case settled)

Maryland PSC Case No. 9104. Cost of Service, Revenue Allocation, and Service Quality issues for Washington Gas Light Company (WGL). July 2007. For Maryland Office of People's Counsel (OPC).

CPUC Rulemaking 06-04-010. Inappropriateness of Avoided Supply-Side Equity Returns as the Basis for Energy Efficiency Incentives. May 2007. For TURN.

Alberta EUB. Application 1492697. Return Margin for Regulated Retail Gas Service provided by Direct Energy Regulated Services. April 2007. For the Alberta UCA.

Alberta Beverage Control Management Board Hearing Review Panel. Return Margin for Bottle Recycling Depots. For Canada's National Brewers. March 2007.

Arkansas PSC Docket 06-124-U. Revenue Requirement and Cost of Service, for Arkansas Western Gas Company (AWG). February 2007. For the Arkansas AG (case settled).

Arkansas PSC Docket 06-101-U. Revenue Requirement, Cost of Service, and Residential Rate Design for EAI. February 2007. For the Arkansas AG.

Alberta EUB. Application 1468565. Policy Testimony Regarding the Establishment of a Uniform System of Accounts for Alberta Electric Utilities. November 2006. For the Alberta Federation of REAs Ltd and Alberta Association of Municipal Districts and Counties (REA/AAMDC), CCA, and PICA.

CPUC App. 06-03-005. Marginal Cost and Class Revenue Allocation for PG&E. October. 2006. For TURN (case settled).

PUCN. Docket 06-06007. Special Contract to Extend Service from Nevada Power to MGM Mirage Project. October 2006. For Nevada BCP.

Arkansas PSC Docket 06-070-U. Revenue Requirement, Cost of Service, and Residential Rate Design for OG&E. October 2006. For the Arkansas AG. (case settled)

CPUC App. 05-03-015. Value of Demand Response and Policy Issues Associated with SDG&E's Proposed Automatic Metering Infrastructure Program. August 2006. For UCAN.

CPUC App. 06-04-012. Ratemaking and Performance Requirements for Two Proposed PG&E Powerplants. August 2006. For TURN.

(PUCN Docket 06-05007. Inquiry on Electric Marginal Cost Methods. July and October 2006. For Nevada BCP (formal comments).

Alberta EUB. Applications 1455025 and 1457764. Return Margin for Regulated Retail Electric Service provided by Direct Energy Regulated Services and Enmax Energy Services. July 2006. For Alberta UCA and several other organizations representing Alberta consumers.

CPUC App. 05-12-005. Revenue Requirements for PG&E's Electric Generation and Electric and Gas Distribution Activities. April. 2006. For TURN.

Alberta EUB. Application 1434992. Allocation of Transmission Costs of Fortis Alberta, Inc. to Customer Classes. April 2006. For REA/AAMDC.

Arkansas PSC Docket 06-028-R. Principles for Integrated Resource Planning. April 2006. For the Arkansas AG. (formal opening and reply comments, prepared jointly with C.K. Mitchell)

PUCN. Docket 05-10003/10005. Electric and Gas Cost of Service and Residential Rate Design for Sierra. February 2006. For Nevada BCP.

CPUC App. 05-05-023. Marginal Cost and Revenue Allocation of SCE. January 2006. For TURN. (case settled)

CPUC) App. 05-06-028. Value of Demand Response in PG&E's Advanced Metering Infrastructure (AMI) Program. January 2006. For TURN.

CPUC App.05-06-028. Impact of Pending Municipal Annexation Proposal in Yolo County on PG&E's AMI Program. January 2006 (deployment) and June 2005 (pre-deployment). For Yolo County and cities of Davis, West Sacramento, and Woodland.

CPUC App. 05-06-018. Revenue Requirements, Marginal Cost, Revenue Allocation, and Residential Rate Design for Sierra's California Operations. November-December 2005. For TURN (two separate pieces of testimony; case settled)

Arkansas PSC Docket 05-111-P. AWG's Proposed Weatherization Program. November 2005. For the Arkansas AG.

CPUC Rulemakings 04-04-025 and 04-04-003. Avoided Cost Policy for Qualifying Facilities. September 2005. For TURN.

Arkansas PSC Docket 05-006-U. Revenue Requirement, Cost of Service, and Residential Rate Design for AOG. August 2005. For the Arkansas AG.

Arkansas PSC Docket 04-176-U. Revenue Requirement, Cost of Service, and Residential Rate Design for AWG. July 2005. For the Arkansas AG.

Arkansas PSC Docket 04-121-U. Revenue Requirement, Cost of Service, and Residential Rate Design for Centerpoint Arkla. May 2005. For the Arkansas AG.

Maryland PSC Case No. 8990. Testimony Supporting Settlement on Interruptible Rate Design, Revenue Normalization Mechanism and Future Residential Rate Design for WGL. May 2005. For Maryland OPC.

CPUC App. 04-12-014. Revenue Requirements for SCE. May 2005. For TURN.

Arkansas PSC Docket 04-141-U. Revenue Requirements, Electric Heat Promotion Policy, and Rate Design for Arkansas Electric Co-operative Corp. March 2005. For the Arkansas AG.

CPUC App. 04-06-024. Electric Marginal Cost and Revenue Allocation for PG&E. March 2005. For TURN (case settled).

CPUC App. 04-11-003. Revenue Requirement Settlement for SDG&E's Palomar Combined Cycle Plant. March 2005. For TURN (joint testimony with SDG&E and Office of Ratepayer Advocates' witnesses)

CPUC App. 04-03-021. Gas Marginal Cost and Residential Rate Design for PG&E. January 2005. For TURN. (rate design issues settled)

CPUC App. 04-02-026. Cost-Effectiveness Analysis of Scenarios for Southern California Edison Company's (SCE's) San Onofre Steam Generator Replacement Project. December 2004. For TURN.

Arkansas PSC Docket 04-100-U. Revenue Requirement, Cost of Service, and Residential Rate Design for Empire. November 2004. For the Arkansas AG. (case settled)

PUCN. Docket 04-5021. Consolidation of Sierra's Liquefied Propane Gas Rates with its Natural Gas Rates. August 2004. For Nevada BCP.

CPUC App. 04-01-009. Cost-Effectiveness Analysis of Scenarios for PG&E's Diablo Canyon Steam Generator Replacement Project. August 2004. For TURN.

Northwest Territories PUB. Evaluation of the Snare-Yellowknife Reliability Criteria of the Northwest Territories Power Corporation. July 2004. For the City of Yellowknife (joint testimony with R. L. Bruggeman).

Arkansas PSC Docket 01-041-U. EAI Request for Transition Cost Recovery. April 2004. For the Arkansas AG.

CPUC Apps. 02-12-027/02-12-028, Phase 2. Economic Evaluation of Performance Based Ratemaking (PBR) Framework for Sempra Energy Utilities. April 2004. For TURN.

PUCN Docket 03-12002. Marginal Cost and Rate Design for Sierra. March 2004. For Nevada BCP (case settled)

Arkansas PSC Docket 02-179-U. Gas Procurement Practices of AWG. March 2004. For the Arkansas AG.

City and County of San Francisco vs. Turlock Irrigation District, Non-Binding Arbitration (before Panelists Hanschen, O'Neill and Power). Regulatory Decisions that Led to the California Energy Crisis. March 2004. For the City and County of San Francisco. (case settled after appearance)

PUCN Docket 03-10001. Marginal Cost and Rate Design for NPC. January 2004. For Nevada BCP.

CPUC Rulemaking 01-10-024 (SDG&E Procurement Phase). Comparison of Costs for Palomar project and Otay Mesa, Mountainview, and Sempra DWR Contracts. January 2004. For TURN.

Alberta EUB. Dockets 1306818 and 1306819. Return Margin for Enmax Energy Corporation's Regulated Retail Tariff and Use of Equity Contributions from Ratepayers to Fund Enmax Power Corporation's Distribution Plant. January 2004. For Enmax Consumer Group (five groups of Enmax customers).

PUCN Dockets 03-6040 and 03-6041. Standby Rate Design for NPC and Sierra. November 2003. For Nevada BCP. (case settled)

CPUC Application 03-07-032. Review of SCE's Mountainview Powerplant. September 2003. For TURN.

CPUC Apps. 02-12-027/02-12-028. Revenue Requirement for SDG&E and Southern California Gas (SoCal Gas). September 2003. For TURN and UCAN.

Alberta EUB Docket 1271597 (Generic Cost of Capital). Business Risk of Alberta Utilities. July 2003. For the Consumer Group (nine Alberta electric and gas consumer groups). (joint testimony with Robert Liddle)

Maryland PSC Case No. 8959. Embedded and Marginal Cost of Service, and Review of Tariffed Service Charges for Washington Gas Light (WGL). June 2003. For Maryland OPC.

CPUC App. 02-11-017. Revenue Requirement for PG&E's Electric Generation and Electric and Gas Distribution Operations. May 2003. For TURN. (case settled after appearance)

Arkansas PSC Docket 02-227-U. Revenue Requirement, Cost of Service, and Residential Rate Design for AWG. May 2003. For the Arkansas AG.

CPUC App. 03-07-032. Review of the Future of SCE's Mohave Coal Plant. April and October 2003, June 2004. For TURN.

CPUC Rulemaking 01-10-024. Renewable Portfolio Standard Implementation. April 2003. For TURN.

California Energy Commission (CEC) Integrated Electricity Policy Report. Electric Resource Costs. February 2003. For TURN (formal comment)

CPUC App. 01-10-011. Revenue Requirement and Electric Generation Demand Forecast for PG&E's Gas Transmission Rates. February 2003. For TURN. (case settled)

Alberta EUB Docket 1275494. Business Risk of Atco Electric. February 2003. For the FIRM Group (Alberta Federation of REAs and Alberta Assn. of Municipal Districts and Counties (REA/AAMDC), Alberta Irrigation Projects Assn., CCA, Alberta Urban Municipalities Assn., and PICA).

CPUC App. 02-05-004. Revenue Requirements and Resource Planning for SCE. December, 2002. For TURN.

Oklahoma Corporation Commission Cause No. PUD 200200166. Revenue Requirements, Cost of Service, and Residential Rate Design for Reliant Arkla Gas. October 2002. For the Oklahoma AG. (case settled)

Arkansas PSC Docket 02-024-U. Revenue Requirements, Cost of Service, and Residential Rate Design for AOG. August 2002. For the Arkansas AG.

CPUC Rulemaking 01-05-047. Demographic Analysis of California Residential Users and Proposals for Surcharge Relief for Lower-Middle-Income customers. August 2002. For TURN.

Alberta EUB Docket 1250392. Cost of Service for Aquila Networks Canada (ANCA). July 2002 For REA/AAMDC. (joint testimony with Arnie Reimer)

Maryland PSC Case No. 8920. Embedded and Marginal Cost of Service, and Analysis of Tariffed Service Charges for WGL. June 2002. For Maryland OPC. (case settled)

CPUC Rulemaking 02-01-011. Exit Fees for Direct Access Customers. June 2002. For TURN.

CPUC Rulemaking 01-10-024. Procurement of Renewable Resources by California Investor-Owned Utilities. May 2002. For TURN.

CPUC App. 00-10-045 et al. Ratemaking for Recovery of AB 265 Balances from SDG&E Customers. May, 2002. For UCAN.

Arkansas PSC Docket 01-243-U. Revenue Requirement, Cost of Service, and Residential Rate Design for Reliant Arkla Gas. May 2002. For the Arkansas AG. (case settled)

PUCN Docket 01-11030. Cost of Service and Rate Design for Sierra. March 2002. For Nevada BCP.

Alberta EUB Docket 1250392. Business Risk of ANCA. March 2002. For the FIRM Group. (this part of case settled)

Alberta EUB Docket 1248859. Transmission Congestion Management Policy. For the FIRM Group. March 2002 (joint testimony with Eric Woychik)

PUCN Docket 01-10001. Cost of Service and Rate Design for NPC. January 2002. For Nevada BCP.

Arkansas PSC Docket 01-184U. Ratemaking for Ice Storm Damage for Entergy Arkansas, Inc., December 2001. For the Arkansas AG. (case settled)

Alberta EUB Docket 1244140. Article 24 Module. Payments to Generators for Transmission Must Run Services. For the FIRM Group. November 2001 (joint testimony with Eric Woychik)

PUCN Docket 01-7023. Revenue Requirement, Cost of Service, and Rate Design of Southwest Gas. November 2001. For Nevada AFL-CIO. (revenue requirements settled)

PUCN Docket 01-4047. Southwest Gas' Rules for Switching between Transportation and Sales Service. October 2001. For Nevada BCP.

Arkansas PSC Docket 00-190-U (second phase). Consumer Impacts of Electric Utility Restructuring. September 2001. For the Arkansas AG.

CPUC App. 00-11-038 et al. Department of Water Resources' Revenue Requirement for Service to Utility Customers. August 2001. For TURN (formal comment)

Arizona Commerce Commission, Dockets G-01551A-00-0309 And G-01551A-00-0127. Cost of Service and Rate Design for Southwest Gas. July 2001. For Complainants (Union Club of Arizona, Public Interest Research Group, et al.)

CPUC App. 00-11-038 et al. Ratemaking for Utility Retained Generation. July 2001. For TURN.

Arkansas PSC. Rate Unbundling testimony in 2001 for four co-ops and three investor-owned utilities, where cases were settled without hearing. January-June 2001. For the Arkansas AG. Details available on request.

CPUC App. 00-11-038 et al. Tiered Rate Design for Emergency Rate Surcharge. April 2001. For TURN.

Nevada PUC. Docket 01-1042. Divestiture of Utility Generating Plants. April 2001. For Nevada BCP. (testimony given orally).

CPUC App. 00-07-001. Marginal Cost and Revenue Allocation for Sierra's California System. February 2001. For TURN. (case settled)

CPUC App. 00-11-038 et al. Utility Financial Issues Related to Emergency Rate Relief. February 2001. For TURN.

CPUC App. 00-11-038 et al. Rate Design for Emergency Rate Relief and Ratemaking for Diablo Canyon Nuclear Plant. December 2000. For TURN.

Arkansas PSC. Rate unbundling testimony for 12 cooperatives where cases settled before hearing. (Cases not settled listed below.) For Arkansas AG. January-December 2000. Details available on request.

CPUC App. 00-05-024. Benefits of Retaining the Palo Verde and Four Corners Powerplants in Regulated Service. November 2000. For TURN and the CPUC's Office of Ratepayer Advocates (ORA). (case rendered moot by legislation)

Alberta EUB. Docket 2000257. Return Margin and Marketing Expenses under Epcor's Regulated Retail Rate Obligation Tariff. October 2000. For the FIRM Group. (case settled)

Alberta EUB Docket 2000136. Cost of Service and Rate Design for Atco Electric Distribution Service. October 2000. For REA/AAMDC.

Alberta EUB Docket 2000258. Testimony on UNCA Distribution Performance-Based Ratemaking (PBR) Proposal. (1) Economic Aspects (Indexing and Sharing). (2) Business Risk of Distribution Wires Business (also filed in Docket 2000136), and (3) Cost of Service. October 2000. For FIRM Group, except cost of service for REA/AAMDC. (case settled)

Arkansas PSC Docket 99-263-U. Rate Unbundling for Southwest Arkansas Electric Cooperative Corporation (ECC). October 2000. For the Arkansas AG. (three-party settlement opposed by industrial intervenor)

CPUC App. 99-03-014. PG&E's Marginal Electric Distribution Cost, Revenue Allocation, and Rate Design. September 2000. For TURN. (case dismissed due to energy crisis)

Arkansas PSC Docket 00-190-U. Consumer Impacts of Electric Utility Restructuring. September 2000. For the Arkansas AG.

CPUC App. 00-04-002. PG&E's Gas Marginal Costs. September 2000. For TURN.

Alberta EUB Docket 2000135. Cost of Service and Rate Design for ESBI Alberta Ltd. Transmission Service. August 2000. For the FIRM Group.

Arkansas PSC Docket 99-249-U. Rate Unbundling for EAI. July 2000. For the Arkansas AG. (settled except rate design)

CPUC App. 99-09-053. Projection of Future Revenue Sharing under Settlement allowing Transfer of PG&E's Hydroelectric Plants to an Affiliate with Revenue Sharing between the Affiliate and Ratepayers. August 2000. For TURN. (testimony never presented, rendered moot by legislation)

Alberta EUB. 2001 GTA for the Transmission Administrator. Rate Design for Reserves and Contribution Policy. August 2000. For the FIRM Group.

Alberta EUB. Ratemaking for Investment Credits for TransAlta's Industrial Customers. June 2000. For the FIRM Group. (joint testimony with J. Nahigian)

California PUC App. 99-09-053. Projection of Valuation and Future Ratemaking Results for Retention of PG&E's Hydroelectric Plants within the Utility. June 2000. For TURN and ORA.

California PUC App. 99-09-006. Ratemaking for Decommissioning of PG&E's Hunters Point Power Plant. June 2000. For City and County of San Francisco.

Wisconsin PSC Docket No. 6630-UR-111. Electric and Gas Cost of Service and Rate Design of Wisconsin Electric Power Company. March, 2000. For the Wisconsin Citizens Utility Board.

New Jersey Board of Public Utilities (BPU). Docket No. EX99090676. Competition and Customer Account Services. March 2000. For the New Jersey Division of the Ratepayer Advocate. (case settled)

CPUC App. 91-11-024 (1999 Rate Design Window). Electric Marginal Cost and Rate Design of SDG&E. March 2000. For UCAN.

CPUC App. 99-03-013 et al. Policy Analysis of Revenue Cycle Services and Energy Service Provider Fees and Charges. February 2000. For TURN.

PUCN Docket 99-7035. Cost Allocation in NPC's Deferred Energy Case. January 2000. For Nevada BCP.

Arkansas PSC. Docket 99-238-U. Unbundled Rates for the Ouachita Electric Cooperative Corp. December 1999. For the Arkansas AG. (case settled)

PUCN Docket 99-4005 Phase 2. Unbundled Distribution Revenue Requirement, Marginal Cost and Rate Design of NPC. November 1999. For Nevada BCP.

Maryland PSC. Case No. 8820. Affiliate Transaction Rules. October 1999. For Maryland OPC. (formal comments)

PUCN. Docket 99-4001 Phase 2. Unbundled Distribution Revenue Requirement, Marginal Costs and Rate Design of Sierra. October 1999. For Nevada BCP.

CPUC App. 99-04-024. SCE's 1997-98 Capital Additions. October 1999. For TURN.

Alberta EUB. Review of Power Purchase Agreements developed by the Independent Assessment Team. Need for Sharing or Reopeners in 20-Year Indexed Generation Contracts. September 1999. For the Consortium (of over 10 Alberta consumer groups and muncipalities). (Joint Testimony with Mark Drazen)

PUCN Docket 99-4005 Phase 1. Unbundling Principles and Revenue Requirement Issues of NPC. August, 1999. For Nevada BCP.

PUCN Docket 99-4001 Phase 1. Unbundling Principles and Revenue Requirement Issues for Sierra. July 1999. For Nevada BCP.

CPUC App. 99-01-016 et al. Treatment of Securitized Revenue Bonds and Revenue Allocation Issues in Post Transition Ratemaking, Phase II. July 1999. For TURN and UCAN.

Alberta EUB. 1999-2000 GTA for the Transmission Administrator. Transmission Rate Design for Reserves. July, 1999. For the FIRM Group.

Arkansas PSC. Docket 98-339-U. Testimony in Support of the Cost of Service Settlement for Southwestern Electric Power Company (SWEPCO). July, 1999. For the Arkansas AG.

CPUC App. 99-01-016 et al. Revenue Allocation issues in Post Transition Ratemaking. July, 1999. For TURN.

Hawaii PUC. Docket 98-0013. Reasonableness of Contract Between Hawaii Electric Light Company (HELCO) and Encogen Hawaii, L.P. March, 1999. For Encogen Hawaii, L.P. (case settled)

CPUC App. 98-10-012 and 98-10-031. Marginal Cost and Rate Design for SoCal Gas and Electric Generation Rate Policy for Sempra Energy Gas Utilities. March 1999. For TURN and UCAN.

Alberta EUB. 1999-2000 General Tariff Applications. Differentiation of Risk among Regulated Functions of the Alberta Utilities. February, 1999. For the FIRM Group

Alberta EUB. Alberta Power Ltd. (APL) 1998 General Tariff Application Phase 2. Cost of Service and Rate Design. November, 1998. Generation and transmission costs for the FIRM Group, distribution costs and farm rate design for REA/AAMDC.

Alberta EUB. TransAlta Utilities (TAU) 1998 General Tariff Application Phase 2. October, 1998. Cost of Service and Rate Design. For the FIRM Group.

PUCN Docket No. 98-9038 and 98-8034. Metering and Billing as Potentially Competitive Services for NPC and Sierra. September, 1998. For Nevada BCP. (identical testimony filed in each docket)

Maryland PSC. Case No. 8791. Jurisdictional Allocation, Cost of Service and Rate Design of Potomac Electric Power Company. August, 1998. For Maryland OPC.

CPUC OII 98-09-007. Report on Tree Trimming Expenditures of PG&E 1987-1997. Direct Testimony July, 1998, rebuttal testimony March, 1999. For CPUC Consumer Services Division.

CPUC App. 97-12-020. Expenses and Capital Projects of PG&E. July, 1998. For TURN.

CPUC App. 98-01-016. SDG&E's Cost of Service and Performance Based Ratemaking. July, 1998. For UCAN.

CPUC App. 98-04-012. Transfer of the El Dorado Hydro Project from PG&E to the El Dorado Irrigation District. For El Dorado Irrigation District.

CPUC App. 96-12-009 et al. Revenue Cycle Service Unbundling. April, 1998. For TURN and UCAN.

CPUC App. 97-10-014 et al. Generation Capital Additions for PG&E and SCE. (PG&E settled) February 1998. For TURN.

PUCN. Dockets 97-11018 and 97-11028. Cost Unbundling of NPC and Sierra. February 1998 and December 1997. For Nevada BCP.

Virginia Corporation Commission. Case No. PUE960296. Stranded Costs, Regulatory Assets, and Alternative Ratemaking for Virginia Power. December, 1997. (part settled; part moved to future docket) For Southern Environmental Law Center.

CPUC App. 97-03-002. Gas Marginal Cost and Rate Design for PG&E. December, 1997. For TURN.

New Jersey BPU Docket EO97070456. Stranded Costs of Atlantic City Electric Company. December, 1997. For New Jersey Public Interest Intervenors (NJPII)

New Jersey BPU Docket EO97070462. Stranded Costs of Public Service Electric and Gas Company. November, 1997. For NJPII.

New Jersey BPU Docket EO 97070459. Stranded Costs of General Public Utilities. November, 1997. For NJPII.

Nevada PUC. Docket 97-8001. Structure for Unbundling Costs of Nevada Electric Utilities. September, 1997. For Nevada BCP.

CPUC App. 96-07-018. Impact of Closure of PG&E's El Dorado Hydro Project on PG&E's Revenue Requirement. September, 1997. For El Dorado Irrigation District.

CPUC App. 96-10-038. Economic and Affiliate Transaction Issues in the SoCal Gas-SDG&E merger. August, 1997. For TURN and UCAN.

CPUC App. 96-08-001 et al. Competitive Transition Charges for the California Utilities. May, 1997. For TURN and UCAN.

Nevada County Municipal Court. People v. Pacific Gas and Electric Company (PG&E) Authorized and Actual Tree Trimming Spending; PG&E Profits. April 1997. (testimony given orally) For Nevada County District Attorney.

CPUC App. 96-12-009. Unbundling Rates for the California Utilities. February 1997. For TURN and UCAN.

Nevada PSC. Southwest Gas Advice No. 346. Cost Allocation for Purchased Gas Adjustment Case. February 1997. For Nevada Office of Consumer Advocate (OCA – later renamed BCP)

PUCT Project No. 16536. Unbundling Electric Distribution Functions. January,1997. For Environmental Defense. (formal comment)

CPUC App. 95-06-002. SoCal Gas' Performance-Based Ratemaking (PBR) Proposal: Indexing, Sharing, Residential Rate Design. October 1996. For TURN and California Department of General Services (DGS).

Washington Utilities and Transportation Commission. Docket UE-960195. Stranded Cost and Other Issues Affecting Merger of Puget Sound Power and Light with Washington Natural Gas. September 1996. For Washington Public Counsel.

CPUC App. 96-03-054. Ratemaking for PG&E's Diablo Canyon Nuclear Plant. September 1996. For TURN.

CEC Docket 95-ER-96. Rate Design Issues in Electric Restructuring. August 1996. For TURN.

CPUC App. 96-02-056. Ratemaking for SCE Share of the Palo Verde Nuclear Plant. August 1996. For TURN.

Alberta EUB. 1996 General Rate Application. Unbundling the Cost of Capital in Alberta's Restructuring. August 1996. For the FIRM Group.

CPUC App. 96-03-031. Marginal Cost and Residential Rate Design of SoCal Gas. July 1996. For TURN.

Northwest Territories PUB. Northwest Territories Power Corporation GRA. Evaluation of Reliability Criteria and the Snare Cascades Hydroelectric Project. May 1996. (case settled) For City of Yellowknife.

PUCT Docket 15000. Generation Market Structure. March 1996. For Environmental Defense (formal comment)

CPUC App. 94-12-005 Phase 2. Marginal Cost, Revenue Allocation, and Residential Rate Design of PG&E. December 1995. For TURN.

Bonneville Power Administration (BPA) 1996 Wholesale Power and Transmission Rate Case. Design of Ancillary Service Rates. September 1995. For Renewable Northwest Project.

CPUC App. 95-05-023 et al. Treatment of Customer Deposits in Utility Capital Structures. August 1995. For TURN.

U.S. District Court, San Diego. James v. Southern California Edison. Case No. 94-1085-J. Ratemaking for Potential Outage for San Onofre 3 before Commercial Operation in 1984. August 1995 (oral testimony). For Glenn James.

CPUC App. 93-12-025. Marginal Cost, Revenue Allocation, and Rate Design for SCE. June 1995. For TURN.

Ontario Energy Board (OEB) Docket HR 23. Cost Allocation and Backup Power Rate Design of Ontario Hydro. June 1995. For Independent Power Society of Ontario (IPPSO).

CPUC App. 94-11-015. Gas Load Forecast and Marginal Cost of PG&E. June 1995. For TURN.

OEB Docket E.B.R.O. 490. Cost Allocation for Ancillary Business Activities of Consumers Gas Company. May 1995. For HVAC Coalition.

CPUC App. 94-12-005. Revenue Requirement Issues for PG&E. May 1995. For TURN.

CPUC App. 94-12-005. PG&E's Customer Service, Phone Center and Disaster Planning. April 1995. For TURN.

British Columbia Utilities Commission. Electric Market Restructuring. April, 1995. For Columbia River Treaty Assn. (client withdrew prior to hearing)

CPUC App. 93-12-029. Evaluation of the Proposed Settlement of SCE's 1995 Test Year Rate Case. February, 1995. For TURN.

CPUC App. 94-10-023. Billing Determinants and Revenue Allocation for SDG&E. January, 1995. For UCAN.

Connecticut Department of Public Utility Control (DPUC). App. 94-04-01. Cost-Effectiveness and Alternative Ratemaking for Connecticut Yankee Nuclear Plant. December, 1994. For Connecticut Cogeneration Coalition and Connecticut Small Power Producers Assn. (CTCC/CSPPA).

OEB Docket E.L.B.R.G. 36. Structure and Governance of Ontario Hydro International, Inc. November, 1994. For IPPSO.

Alberta PUB. APL Phase II GRA. Evaluation of APL's Cost of Service Study. September, 1994. For REA/AAMDC.

CPUC App. 93-12-029. Evaluation of PBR for SCE. September, 1994. For TURN, DGS, EDF, Natural Resources Defense Council and Center for Energy Efficiency and Renewable Technologies.

Hawaii PUC. Docket No. 94-0079. Avoided Cost for HELCO and Price Offer Proposed by Enserch Development Corp (EDC) for Combined Cycle Cogeneration. September, 1994. For EDC.

CPUC App. 93-09-006. Marginal Cost, Billing Determinants, and Residential Rate Design for SoCal Gas. June, 1994. For TURN.

Nevada PSC Docket 93-11045. Marginal Cost and Revenue Allocation for NPC. June, 1994. (case settled) For Nevada OCA.

OEB Docket HR 22. Integrated Resource Planning at Ontario Hydro; Backup Power and Experimental Rate Design. May-June 1994. For IPPSO.

CPUC App. 93-12-025. SCE's Revenue Requirements.. April, 1994. For TURN.

CPUC App. 93-12-025. SCE's Demand-Side Management Programs. April, 1994. For DGS.

Chaminade Ltd. v. Owl Companies. American Arbitration Assn. History of PG&E Rate Design in the 1980s; Cost to Chaminade of Electricity and Fuel with and without Cogeneration. April, 1994. For Owl Companies. (oral testimony)

Hawaii PUC. Docket No. 7623. Timing of Power Need and Cost of New Combined Cycle Generation for HELCO. March, 1994. For EDC.

CEC Docket 93-ER-94. Northwest Power Availability. February, 1994. For the Independent Energy Producers Assn. (IEP).

Manitoba PUB. Manitoba Hydro 1994/95 GRA. Evaluation of Diesel Zone Costs and Rates. February, 1994. For Government of Canada, Department of Justice.

CPUC Application 92-10-017. SDG&E's PBR Base Rate Proposal. December 1993. For UCAN.

Alberta PUB. 1994 EEMA Forecast. Limits on Interruptible Loads; Energy Constraints in Alberta Utility System Planning. September 1993. For REA/AAMDC.

Connecticut DPUC. Docket 93-04-001. Fossil Plant Retirement Economics for Northeast Utilities (NU). August, 1993. For CTCC/CRRA.

CPUC App. 93-05-008 et al.. Evaluation of Proposal to Increase Equity Capital Ratio of Electric Utilities Due to Alleged Purchased Power Risk. August, 1993. For TURN.

OEB E.B.R.O. 483/484. DSM Program Design for Centra Gas Ontario. August, 1993. For Ontario Green Energy Coalition (GEC). (case settled)

OEB E.B.R.O. 485. DSM Program Design for Consumers Gas. August, 1993. For GEC. (case settled)

Yukon Utilities Board. 1993/94 General Rate Application of Yukon Energy Corporation/Yukon Electric Company Limited (YEC/YECL). Revenue Requirements; Rebuttal Testimony on Cost of Service. June 1993. (principal author with J. Helmich, M. Davies, and B. Walt) For City of Whitehorse.

CPUC App. 92-09-040. SDG&E's Fuel Budget Issues. May, 1993. (case settled) For UCAN.

CPUC App. 92-11-017. SoCal Gas' Low Income Conservation Programs. March, 1993. For California-Nevada Community Action Assn. (Cal-Neva) and The East Los Angeles Community Union .

CPUC App. 92-10-017. SDG&E's Performance Based Ratemaking for Generation and Dispatch. March, 1993. (case settled) For UCAN.

Hawaii PUC. Docket No. 7310. Avoided Cost Methods for Hawaiian Electric (HECO), HELCO, and Maui Electric (MECO). Direct, February, 1993, rebuttal May, 1993. For Hawaiian Sugar Planters Assn. (HSPA) and Wailuku River Hydro Company.

Ontario Environmental Assessment Board (EAB). Ontario Hydro Demand/Supply Plan (DSP). Alternative Supply Futures for the Ontario Hydro System. January, 1993. (utility withdrew filing) For IPPSO.

Maryland PSC. Case No. 8469. Cost of Service and Rate Design of Potomac Edison Company. November, 1992. For Maryland OPC.

Yukon Utilities Board. Capital Budget of YEC/YECL. Demand Forecasting, DSM Program Design and Evaluation, Other Supply Issues. October, 1992. For City of Whitehorse.

Ontario EAB. Ontario Hydro DSP. Utility Planning Concepts and Tools; Reliability of Non-Utility Generation; Uncertain Economics of Continued Operation of Bruce A Nuclear Station. September-October, 1992. For IPPSO.

CPUC Case 91-11-029 et al. Mobile Home Park Submetering Discounts and Obligation to Charge Park Residents Tariff Rates without Capital Surcharges. September, 1992. For Golden State Mobilehome Owners League. (formal comment)

CPUC App. 91-11-024. Marginal Cost and Rate Design for SDG&E. September, 1992. For UCAN. (case settled except residential rate design)

Connecticut DPUC Docket 92-04-001. Avoided Costs and Resource Plans, and Cost of Compliance with Clean Air Act Regulations of NU and United Illuminating (UI). August, 1992. For CTCC/CRRA.

CEC Docket 90-ER-92. PG&E's Required Reserve Margin and Need for Power. July, 1992. For IEP. (principal author)

Conawapa Environmental Review Panel (Joint Canada/Manitoba EAB). Electricity Planning Scenarios for Scoping the Analysis of Conawapa Dam. July, 1992. For Sierra Club of Western Canada and other environmental intervenors.

New Mexico PSC Case No. 2426. Cost of Service, Residential Demand Charges and Rate Design for Otero County Electric Co-operative. June, 1992. For the Alto Group of residential customers. (case settled)

OEB Docket HR 21. Uncertainties in Economics of Rehabilitating and Retubing Ontario Hydro's Bruce A Nuclear Plant. June, 1992. For IPPSO.

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