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May 15, 2012 File no: 1531.006

Via E-mail

Alanna Gillis
Acting Commission Secretary
British Columbia Utilities Commission
P.O. Box 250
6th Floor, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Gillis:

Re: Project No. 3698622 British Columbia Hydro and Power Authority (BC Hydro) Amended F2012-F2014 Revenue Requirements Application COPE Responses to Information Request No. 1 of BC Hydro and Power Authority, BCOAPO, BCSEA/SBC and AMPC

Please find attached on behalf of COPE the following responses to the Information Requests delivered in respect of Mr. Pullman's evidence (Exhibit C2-16):

(a) COPE Responses to BC Hydro and Power Authority Round 1 Information Requests (Ex. B-28);

(b) COPE Responses to BCOAOPO Round 1 Information Requests (Ex. C1-15);

(c) COPE Responses to BC Sustainable Energy Association and Sierra Club of British Columbia Round 1 Information Requests (Ex. C10-15); and

(d) COPE Responses to Association of Major Power Consumers Round 1 Information Requests (Ex. C18-11).

Please call or email if you have any questions or require any further information.

Yours truly,

Hunter Litigation Chambers

Per:

Mark S. Oulton
MSO/bb
Encls.
cc Distribution List – BC Hydro F2012 – F2014 RRA

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REQUESTOR NAME: BCOAPO

Information Request No. 1.1 to COPE
British Columbia Hydro and Power Authority Amended F2012 to F2014 Revenue Requirements Application

1.0 Topic: Priority of Recommendations

Reference: Exhibit C2-16

1.1 Please prioritize your recommendations.

Response:

One of the reasons that COPE is participating in these proceedings is to ensure that BC Hydro, as a major employer of COPE members, continues to be a well regulated, well managed and well governed Crown Corporation and utility. One of the main threats to COPE's vision is the proliferation of deferral accounts and the growth in value of the critical deferral accounts which are being used to mask the true impact of increases to BC Hydro's cost structure from BC Hydro's ratepayers. COPE's recommendations are designed to accomplish two goals i) to point out to the Commission the more egregious instances of cost deferral in the current application and ii) to suggest to the Commission ways to take control over BC Hydro's deferral accounts and the amount deferred therein, in the future.

Recommendations 1 and 8, 9 10 and 11(as well as 3 and 5 to some extent) all fall into the first category. They relate to BC Hydro's Amended Application and the way in which BC Hydro has allowed its "agreement" with the Review Panel to determine its deferral policies. They will have to be addressed by the Commission in the current proceeding, and might thus be considered as priority recommendations.

Recommendations 1 to 8 all have some reference to the future management of the accounts by the Commission in the future. They need to be addressed in this application, but will not have an immediate impact on BC Hydro's rates.

REQUESTOR NAME: BCOAPO

Information Request No. 2.1 to COPE
British Columbia Hydro and Power Authority Amended F2012 to F2014 Revenue Requirements Application

2.0 Topic: Rate shock

Reference: Exhibit C2-16, Table, page 19

2.1 If the Revenue Requirement shortfalls shown in the Table were collected as shown in fiscal years 2013 and 2014 and the 2012 shortfall was collected over a 5 year period, the resulting rate increases would be approximately 8% for 2012, 12.5 % for 2013 and 8% for 2014. What is COPE's position on rate shock, generally defined as an annual rate increase of more than 10% per year, and rate smoothing?

Response:

In order to provide the proper context for COPE's position on "rate shock", this response to the question is in two parts, first a review COPE's recommendations to the Commission, and then discussion of "rate shock" and "rate smoothing."

COPE's recommendations to the Commission (Ex. C2-16, at pp.19-21) were that BC Hydro had understated its revenue requirements by at least the following amounts:

- F2012 $234.3 million;
- F2013 $269.6 million; and
- F2014 $394.8 million.

In addition, there were amounts COPE could not calculate in respect of amortization of deferred charges which BC Hydro had elected not to commence amortizing in the test period.

BC Hydro has closed its books on F2012 and a final decision from the Commission on its Amended Application is unlikely to be received until BC Hydro's third quarter of F2013. Accordingly, COPE recommended that the Commission approve BC Hydro's recovery of these amounts by way of a Rider. COPE does not take any position or make any specific recommendation with respect to the amount of the Rider or the period over which the amounts might be recovered. Indeed, COPE expresses the pious hope that BC Hydro's shareholder might forego the opportunity of collection (Ex. C2-16, at pp.20-21)

One of the major problems with BC Hydro's rate strategy over the recent period has been its willingness to disguise the true impact of its rate increases from its customers. In F2011, customers received a rate increase of 6.11% that was offset by a credit of 4.71% for the last quarter together with a reduction in the DARR from 4% to 2.5%. This was achieved by a number of means, including:

- rate smoothing of the impact of the Waneeta acquisition ($50 million);
- the transfer of the increase in energy costs to the NHDA ($ 222.5 million);
- the one-time release of the credit balance on the Total Finance Charges Regulatory Account to reduce revenue requirement ($104.7 million); and
- a reduction to customers' bills ($43.8 million).

This suggests that the increase for F2011 should have been in the order of 10% or 12%, and that BC Hydro's proposed increases of 9.73% for each of F2012, F2013 and F2014 were also likely understated, especially when one considers that BC Hydro made no attempt to set the DARR at 5%, where it should have been set. This does raise the question of what qualifies as "rate shock" and whether smoothing is possible if the trajectory of cost increases is constant and increasing.

Against this backdrop, we can address "rate shock". "Rate shock" was discussed by the Edison Electric Institute of the US which in June 2007 commissioned a report by the Brattle Group entitled "Rate Shock Mitigation" and a copy is attached as Exhibit 1 to this response.

EEI's report largely deals with rate shocks caused by such events as the commissioning of major new assets, the end of price caps in deregulated markets, and steep increases in the price of natural gas for generation. In BC Hydro's case the cost increases being experienced and projected by BC Hydro are, in the main, driven by the government-imposed policy of self-sufficiency, by the need to maintain ageing equipment, and by government mandated programs like SMI.

Our understanding of the 10% threshold referred to in the question was that in B.C. it was a bill impact test that BC Hydro applied when rebalancing customer rates, rather than a true definition of rate shock. In its 2007 and 2008 Rate Design Applications BC Hydro sought to demonstrate the justness and reasonableness of the rates it proposed to adjust by applying a set of criteria that included this bill impact test. It is unlikely that, when applying the *Utilities Commission Act*, the Commission would deem a cost-based rate increase to be inherently "unreasonable" within the meaning of the statute because it exceeded 10%.

That being said, the Commission must exercise its authority and judgement to shape the trajectory of BC Hydro rates so as to minimize the amount of harm inflicted on customers, and particularly on vulnerable households, flowing from escalating cost. Mere postponement of cost recovery, in order to spare current customers but compounding the adverse impact on future customers, is not a rational or viable solution.

Turning to rate smoothing, a number of options exist. Some are beyond the powers of the Commission, but are enumerated below, including:

- some form of phase-in for major capital additions. This will most probably become an issue for BC Hydro's ratepayers following commissioning of Mica 5, Mica 6, 5L83 and related capacitor station and transmission upgrades between Mica and NIC, since these high-cost assets will add very little additional energy to the system. It may even be a solution for the new meters, but it is unclear whether the lifespan of the new meters will be of sufficient length for phase- in to make much difference. In that regard, it may be

useful for the Commission to compare the warranty negotiated between BC Hydro and the meters' manufacturer and filed in confidence in response to COPE IR 1.16.2 (Exhibit B-16-3-1), which presumably reflects the manufacturer's willingness to bear the risk of the longevity of the devices in relation to the service life projected in this proceeding by BC Hydro and incorporated into the proposed 20-year amortization period.

- some form of mitigation of the return earned by BC Hydro. While Terasen Gas Inc is allowed a return of 9.5% after tax, HC2 (as amended) makes it possible for BC Hydro to earn closer to 21% on its book equity, before and after tax as it is not taxable;
- some form of reduction in water rentals, as suggested by the Review Panel (Exhibit B-1-3, Appendix BB, p.11); and
- the application of the Downstream Benefits under the Columbia River Treaty to reduce BC Hydro's cost of service (Exhibit B-25, COPE 2.91.1).

BCOAPO

Information Request No. 2.1 to COPE

EXHIBIT 1

Rate Shock Mitigation
The Brattle Group - F. Graves et al.
Prepared for the Edison Electric Institute

June 2007

EDISON ELECTRIC INSTITUTE

Rate Shock Mitigation

Prepared by:

Frank Graves

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The Brattle Group

Prepared for:

Edison Electric Institute

June 2007

The Brattle Group

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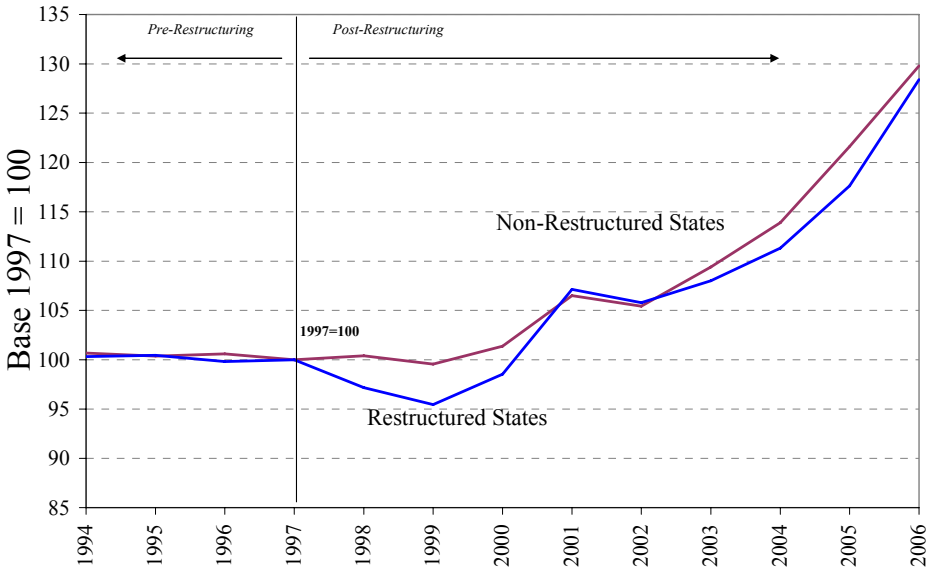
I. INTRODUCTION AND BACKGROUND

Primarily as a result of rising input costs, many U.S. electric utilities are seeking rate increases; in some cases, very substantial increases. This phenomenon is occurring in all regions of the country and in states with traditional regulation as well as those with retail access. No state or utility is immune from the cost pressures that are causing rates[1] to increase. Figure 1 shows an index of electric retail rates over the past 12 years, and it confirms that rates have risen sharply in the past few years after a long period of stability, regardless of regulatory structure.

Figure 1: U.S. Retail Electric Rates from 1994 to July 2006



Sources and Notes:
EIA Data: SEDS, Form 861, Monthly Energy Review, and Form 826.
2006 reflects January 2006 - July 2006 monthly data.

There are various underlying reasons for these rate increases. Input costs, particularly fuel costs, have increased substantially over the past few years. Fuel and purchased power costs account for roughly 95 percent of the cost increases experienced by utilities in the past five years.[2] The increases in the cost of these fuels have been unprecedented by historical standards, affecting every major electric industry fuel source. For example, natural gas, which accounts for nearly 20 percent of all generation, experienced a more than 100 percent increase in spot prices between 2003 and 2005. Fuel price increases, in turn, have affected the cost of power purchased by many utilities. The price of purchased power has increased between 200 and 300 percent in many power markets across the U.S. over the past few years.

[1] For the sake of simplicity, we use the term "rates" to apply both to prices set by regulators under cost-of-service regulation and to the market price for generation, as set in centralized or bilateral wholesale markets. In other words, the term "rate" refers both to cost-based rates set by state regulators as well as market-based rates established pursuant to FERC oversight and regulation.

[2] See *Why Are Electricity Prices Increasing?* Prepared by *The Brattle Group* for the Edison Foundation, June 2006, p. 2.

Moreover, significant new generation, transmission, and distribution infrastructure is needed to meet growing customer demand and to replace antiquated equipment. This expansion will place ongoing pressure on rates. The Energy Information Administration (EIA) and the North American Electric Reliability Council (NERC) both project that more than 50,000 megawatts (MW) of new generating capacity will be needed to meet demand growth through 2014. Transmission investment, after a long period of decline, began a significant upward trend in 2000, totaling nearly $18 billion in the period 1999 to 2003. A recent Edison Electric Institute (EEI) survey shows that its members have spent and plan to spend nearly $29 billion on transmission over the period 2004-2008, a 60 percent increase over the previous five years. Between 2000 and 2004, distribution investment increased from about $10.5 billion to $12.5 billion, a 19 percent increase. If recent investment trends persist, distribution investment will average $14 billion per year over the next 10 years—approximately triple the amount of transmission spending. Additional investment will be required to comply with known (e.g., renewable portfolio standards) and still uncertain but tightening environmental mandates.

Some recent rate increases, particularly those requested by utilities in retail-access states, are being spurred by the expiration of multiyear rate freezes or rate caps implemented at the start of the "transition period" to retail competition. These rates typically were set at a modest discount to the utility's cost-based retail rates in effect immediately prior to the introduction of retail competition and held constant for a three-to-six-year period. The original intent was for most retail customers to migrate to competitive retail energy suppliers, with the local utility providing transmission and distribution service.

While a fairly healthy retail market for large customers has developed in some retail-access states, small customers, for the most part, do not have retail service options and continue to purchase power from the local utility. As a result, local utilities continue to be the primary generation supplier and, upon the expiration of their rate freezes, have had to procure generation supply from the wholesale market at market-based prices. Since wholesale prices have increased significantly in the past few years, the transition from frozen, 1990s vintage, cost-based generation rates to current market-based generation prices has led to significant rate shock in many retail-access states.

In some retail-access states, utilities have requested rate increases as large as 70 percent. For example, customers of Pike County Light & Power Co., a small utility in northeastern Pennsylvania, experienced a 70 percent increase in January 2006 when price caps expired and the utility was forced to procure generation supply from the market. Similarly, Baltimore Gas and Electric Co. initially requested a 72 percent rate increase to take effect on July 1, 2006, to cover the cost of market-based generation supply. (This requested rate increase ultimately was lowered significantly through a rate deferral imposed by the Maryland Legislature.) Not all retail-access states have reached the end of their transition periods, so numerous customers could face comparable "rate shock" over the next few years.

This upward pressure on electric rates is occurring at a time when the industry's average return on equity (ROE) is trending downward. While the overall financial condition of the electric utility industry is sound, over the past five years the typical credit rating of utilities has dropped from A to BBB. Only about 45 percent of all utilities currently maintain ratings of BBB+ or above, down from 75 percent in the late 1990s. About 20 percent of utilities are below investment grade. Moreover, utility cash flows were about $10 billion less than the sum of operating and capital costs in 2005, and this gap could widen significantly during the next several years as utilities undertake expenditures for infrastructure development and environmental improvements. Rejected or delayed rate relief would, of course, only worsen the situation.

Largely overlooked in the firestorm resulting from recent electricity rate increases is the fact that most electricity rates have decreased in real terms over the past 20 years. Moreover, recent electricity rate increases have been modest compared to the sharp increases in prices for other consumer energy products such as gasoline. Unfortunately, this historical perspective provides little solace to electricity customers facing significant rate hikes. Such increases are inherently controversial and often vigorously opposed, irrespective of historical rate trends or a utility's obvious need for rate relief because of significant uncontrollable increases in input costs.

In order to reduce the "pain" associated with large rate increases, state regulators are considering various methods of deferring or phasing in rate increases. Not surprisingly, such alternative rate methods or mechanisms also received consideration whenever the industry was facing significant rate increases in the past, such as the period roughly from the mid-1970s through the mid-1980s. During that era, rate increases were driven primarily by fuel price increases and the completion of the last major construction cycle of base-load generation. At that time, many state commissions considered ways of moderating the rate impact associated with the inclusion of large new power plants in a utility's rate base. Today's rate increases have been driven more by operating cost increases, but the underlying desire to moderate large rate increases is the same.

This report will review and assess various methods of mitigating rate shock consistent with providing a utility a fair opportunity to recover its prudently incurred costs and to maintain a reasonable level of financial health. We will assess both fundamental changes from "traditional" ratemaking as well as more ad hoc approaches. In addition, the report will discuss ways of **preventing** future rate shocks through planning, procurement and ratemaking policies. However, we do not provide a detailed discussion of resource planning and procurement and risk management, which is beyond the scope of this paper.

II. OVERVIEW OF ELECTRIC RATEMAKING PRACTICES

A primary goal of ratemaking is to give a franchise utility a "fair" opportunity to recover its costs, including a return of and on capital invested in utility service. Absent a fair opportunity to recover its costs, a utility will have trouble raising the capital needed to provide adequate and reliable service (or raising it at a reasonable cost). Regulation does not "guarantee" full cost recovery, but it does give a utility an unbiased opportunity to recover its prudently incurred costs, meaning that the utility has an equal opportunity to earn more or less than its cost of service.

In simple terms, a utility's cost of service or revenue requirement consists of three primary elements: (1) operating costs, such as fuel costs, purchased power costs, operations and maintenance (O&M) costs and customer service costs; (2) a return of capital cost, otherwise known as depreciation expense; and (3) a return on capital cost, including applicable income taxes. These costs must be deemed prudently incurred to be eligible for recovery. Often the allowed costs are determined over a historical or projected 12-month "test period" to establish a utility's revenue requirement. Once the test-year revenue requirement is determined, rates remain fixed until the next rate hearing, though most utilities have adjustment clauses that allow them to modify their rates—up or down—to recover fuel and other volatile operating costs on a more frequent basis.

In the early history of the electric power industry, both regulators and the courts grappled with the problem of determining how to set utility rates and, in particular, how to "value" a utility's investment in infrastructure. In non-regulated industries, the economic value to investors of any given asset is equal to the net present value of the expected cash flows generated by that asset. This assessment is difficult to apply in the context of regulated utilities, because the future revenue derived from the assets is itself determined by the regulator. In a regulated industry, rates cannot be set at levels that are consistent and fair in relation to the market value of the firm's assets because those market values only are affected by the allowed rates. There is an obvious circularity problem in regard to utility asset valuation or, more generally, the valuation of a utility's "rate base."

In the first half of the 20th century there was a vigorous debate, which has continued to some extent through today, between those who argued that a utility's rate base should be valued at its original cost and those who argued that the rate base should be valued at its "replacement" or "reproduction" cost. Valuing a rate base according to its replacement or reproduction cost also is known as a "fair value" rate base. The primary advantage of using original, historical cost is that this value is certain and measurable; a utility provides the data necessary to establish the construction cost of an asset, such as a generating plant. The primary advantage of using replacement or reproduction cost is that it is more consistent with an asset's economic value, i.e., rates reflect the current cost of constructing or replacing the asset in current dollars. The primary disadvantage of valuing assets on the basis of their replacement cost is that replacement cost is subject to estimation error and controversy.

An early U.S. Supreme Court decision (*Smyth v. Ames*, 1896) found that both original cost and replacement cost were valid ways of setting a utility's rate base. The Supreme Court's views fluctuated over the next 50

years, but the issue was finally put to rest in the *Hope Natural Gas* case. In this decision the high court said, in effect, that the reasonableness of the ultimate result, rather than the method used to set the rate, determined whether the rate was just and reasonable. Following is an oft-cited passage from that decision:

> Under the statutory standard of just and reasonable it is the result reached not the method employed which is controlling…It is not theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial enquiry under the Act is at an end. The fact that the method employed to reach that result may contain infirmities is not then important.

Grout, *et al.* (2001), concludes that the long-term effect of the *Hope* decision was to popularize use of original, historical cost as the preferred measure of the rate base. A 1992 study by the National Association of Regulatory Utility Commissioners (NARUC) revealed that, as of 1991, 44 regulatory commissions were using original cost, with the remainder either using fair value or having no predetermined method of setting rate base.[3] Hence, setting a utility's rate base equal to original cost less depreciation has become the standard approach to electric ratemaking.

Most utility assets are subject to straight-line depreciation, which means that the plant is depreciated at a constant rate over its assumed operating life. Thus, a plant with an original cost of $1,000,000 and an assumed operating life of 20 years would incur a depreciation expense of $50,000/year for 20 years. Original cost ratemaking, coupled with straight-line depreciation, leads to cost recovery that is "front-end" loaded. This means that much of the asset's value is recovered in the early years of its operating life. See the box for a numerical example of front-end loading.

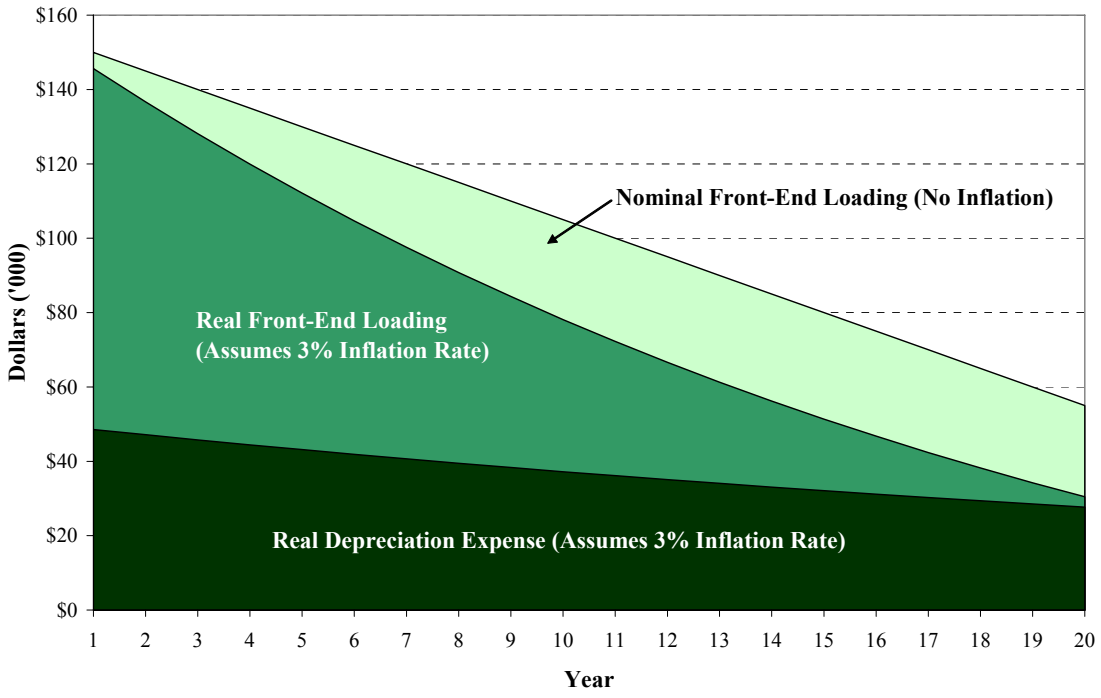
The upshot is that depreciated original cost (DOC) ratemaking is inherently front-loaded. Therefore, such ratemaking can result in a corresponding initial rate shock associated with the introduction of a new generation, transmission or distribution asset into a utility's rate base. By concentrating capital recovery in the early years of an asset's service life, DOC ratemaking exacerbates any near-term rate impacts associated with new assets, regardless of the cost-effectiveness of the asset (or its cost relative to the utility's embedded cost).

[3] Grout P.A. and A. Jenkins (2001), "Regulatory Opportunism and Asset Valuation: Evidence from the US Supreme Court and UK Regulation," The Centre for Market and Public Organization, Working Paper Series No. 01/38.

Illustration of Front-End Loading

Assume a utility brings a new power plant into service. The construction (original) cost of the power plant is $1,000,000. The plant is expected to have an operating life of 20 years. The utility's cost of capital (debt and equity) is 10 percent. In the plant's first year of operation, its revenue requirement would be $100,000 (return on capital) plus $50,000 (depreciation expense) for a total of $150,000. (The plant also would have associated O&M and fuel costs but our focus here is solely on capital recovery.) In year two of its operation, the plant's revenue requirement would be $95,000 (return on capital) plus $50,000 (depreciation expense) for a total of $145,000. In year ten the total revenue requirement would be $100,000. As the undepreciated portion of the plant declines, the associated return on capital declines, because the rate of return is applied to a declining plant value. Since depreciation expense remains constant over time, the annual revenue requirement associated with the plant's capital recovery necessarily declines. The capital recovery method is "front-loaded" because recovery is greatest in the early years of the plant's operation. This is true in nominal, undiscounted dollars, and it is even more pronounced in real, inflation-adjusted dollars, or in discounted present value dollars. Thus, investors do not recover their capital evenly over time, even when depreciation is constant.

Revenue Requirement with Depreciated Original Cost Calibration



Cost-based ratemaking doesn't have to be front-loaded. Indeed, there are alternatives to DOC ratemaking that yield different capital recovery streams that are not front-loaded, but offer the same present value costs (and cost recovery) to customers and investors. Each of these is explained in more detail in subsequent sections of the report.

- One alternative method is the previously mentioned approach of valuing rate base according to its replacement or reproduction cost. Under replacement cost, the value of new assets will increase over time (in nominal terms) rather than decline. This approach has to be balanced with a reduction in allowed returns.
- Another approach is to "levelize" capital recovery either in nominal or real terms. Under nominal levelization, the utility annually would recover the same amount of revenue over the asset's operating life. Under real levelization, the annual capital cost recovery would increase every year (in nominal terms) with the rate of inflation, while the allowed return would exclude any allowance for inflation. Levelized rates, whether real or nominal, yield the same discounted lump-sum revenues over the asset's operating life as the utility would earn under DOC, but the pattern of capital recovery is more stable rather than front-end loaded.
- Incentive or performance-based regulation (PBR) is another alternative to traditional DOC ratemaking. PBR partially breaks the link between costs and rates by giving utilities an explicit opportunity to earn more or less than their approved return on capital. The objective is to allow utilities that operate efficiently and cut costs to earn more profit and to financially penalize poor-performing companies. The best-known form of PBR is price cap regulation, in which prices typically are allowed to increase every year or periodically at a rate equal to inflation less an assumed productivity offset (i.e., a percentage of the inflation rate). A utility that keeps its annual cost increase below the allowed rate increase under the price cap formula benefits financially. Depending on its design, PBR could give a utility an incentive to levelize or lengthen the pattern of capital recovery so as to keep its costs at or below the price cap.
- Another alternative is to couple some type of deferral or phase-in mechanism with traditional DOC ratemaking. Under this approach, rates still are based on the principles of DOC, but near-term rates and the timing of capital recovery are adjusted so as to minimize the near-term rate impact associated with a new asset. For example, a utility could "phase in" the full revenue requirement associated with a new asset, such that the full rate impact would not be reflected in customer rates until several years after the asset enters service. Near-term revenue shortfalls would be recovered, with an allowed return accruing during the deferral period, in later years of the asset's service life. These rate deferral methods, which will be discussed further in the next chapter, became somewhat prominent in the 1980s, during the completion of the industry's last major construction cycle. Inclusion of new base-load generating plants in rate base, particularly nuclear plants, often necessitated a significant rate increase. This, in turn, led regulators to consider means of "mitigating" the rate impacts. Rate deferrals or phase-ins have not been much of an issue until recently, largely because of declining costs through the 1990s, less investment as the industry worked off the generation surplus from the 1980s, increased reliance on purchased power rather than self-constructed generation, and restructuring. However, several utilities are now phasing in rate increases that would otherwise occur more quickly.

Automatic Adjustment Clauses

Non-capital costs comprise a significant portion of a utility's revenue requirement. Most states with traditional retail electric markets (*i.e.*, states in which retail service is provided by a regulated electric utility

with an exclusive franchise service area), separate the review, approval, and recovery of certain frequently changing costs, such as fuel and purchased power costs, from the corresponding scrutiny of the more fixed and predictable capital and operating costs associated with financing and maintaining the assets of the utility.[4] The more variable, unpredictable costs are recovered in rate components that are allowed to change periodically—at least every year and in many cases more frequently—without the need for a full rate case that reviews all of a utility's cost of service. Instead, these rate components are allowed to change roughly contemporaneously with changes in the utility's underlying related costs. These cost recovery mechanisms go by different names, but here we discuss them under the general appellation of "Automatic Adjustment Clauses" or AACs.

AACs for fuel costs arose in the U.S. initially in response to escalating coal prices during World War I. They became prominent again in the 1970s, when the oil price shocks spurred by OPEC became large and economically critical. Such events dramatized the utilities' financial exposure to costs they could not control, and on which they earned no profits. (At that time, oil comprised a much larger portion of the electric generation fuel mix than it does today.) Traditional rate proceedings, in which months of preparatory analyses are required, followed by 6-12 months typically elapsing before a Commission acts upon a utility's rate filing, were deemed too slow to deal with volatile and rapidly rising fuel expenses. As a result, since the 1970s, most states and most utilities have some degree of contemporaneous "flow through" of at least a portion of fuel costs, as well as fuel transportation costs, short term purchased power, and emission allowance costs. In addition, certain capital costs associated with mandatory investments, such as the capital cost of environmental compliance investments, sometimes are recovered through an AAC as well, because such investments are beyond the utility's discretion.

In contrast to the ratemaking treatment of capital investments, such as a new generating plant or transmission line, recognition in allowable rates of incurred AAC costs does not require *a priori* review and approval, except to the extent of confirming the appropriateness of the type, procurement process, and accounting for such costs. Moreover, recovery of AAC costs is timely and assured enough that the risk of non-recovery is very low; in particular, such risk is low enough that it does not compromise the debt ratings and creditworthiness of the utility.

Having an AAC in place will help mitigate customer exposure to the large rate shocks that can arise if rising commodity and other input costs above some allowed level are deferred and accumulated in a balancing account to be reflected in a utility's rates some time in the future. An AAC will tend to "smooth" a utility's rate profile by adjusting rates periodically to reflect rising fuel and purchased power costs. Absent an AAC, a utility may need to significantly increase its retail rates if fuel and purchased power costs increase substantially above the level assumed in the utility's last rate case.

[4] Utilities in restructured states typically have an AAC that permits them to track and recover their purchased power costs on a dollar-for-dollar basis.

III. RATE DEFERRALS

One way of mitigating rate shock is through alternative ratemaking approaches that alter the timing and pattern of capital recovery compared to DOC ratemaking (i.e., reduce the front-end loading associated with DOC ratemaking). These approaches **systematically** change the pattern of capital recovery and the calculation of the utility's revenue requirement, and they aren't necessarily used just to mitigate rate shock. Some of these ratemaking approaches apply specifically to the inclusion of new assets in the utility's rate base, whereas others apply more generically to any new cost incurred by the utility. We define rate deferrals, in contrast, as essentially an ad hoc, case-specific adjustment to rates to mitigate rate shock. The remainder of this section will address rate deferrals.

The basic intent of a deferral or phase-in of a rate increase over a multiyear period is to spread the "pain" associated with the rate increase over a longer period. A rate deferral is simply deferred recovery of a utility's prudently incurred costs. Thus, if $70 million of an approved $100 million rate increase is deferred, the utility should be permitted to recover the $70 million plus carrying charges at a later time such that it is held financially harmless. Otherwise, the utility is not being given a fair opportunity to earn its revenue requirement. To accomplish this objective, the deferred amount must be (1) a credible regulatory asset, (2) allowed to earn a fair carrying change (the carrying charge can be lowered with secure recovery), and (3) assured of being fully amortized. Referring to the above example, the $70 million would become a regulatory asset that would be amortized over a specified, future period. A carrying charge equal to the utility's average weighted cost of capital would be applied to the unamortized balance.

There are at least three drawbacks associated with the simple rate deferral described above. First, consumers ultimately pay more in absolute (total) dollars (though not in present value terms) for electric service with the deferral than they would have otherwise, because they must pay the utility's carrying charge on the unamortized balance. Second, a deferral could force a utility to borrow a substantial amount of funds, which could harm its credit rating and cash flow. Indeed, a utility just finishing a large construction project already could be financially strained, and having to go to the market to borrow funds for a rate deferral would place further stress on its cash flow and credit rating. Third, it may be difficult to assure the reliable future recovery of the deferred amounts. Deferrals could be problematic in an environment in which costs are expected to rise steadily for several years, if the cumulative bill associated with a series of rate deferrals becomes prohibitive. That is, mitigating the initial rate shock associated with multiple rate filings could result in a more significant shock down the road.

To address these and other concerns associated with rate deferrals, some utilities have used a financing technique known as securitization. For example, Baltimore Gas and Electric Co. is using securitization to finance more than $600 million of deferred generation supply expenses. In general, securitization involves the transfer of a revenue-producing asset to a legally separate special purpose entity (SPE) that will issue debt obligations secured by and payable from the revenue stream from the asset. The terms of the asset transfer as well as the various charter provisions and operating procedures of the SPE are designed to insulate the SPE and its obligations from the credit or bankruptcy risks of the transferor of the asset. Securitization was first used by the electric utility industry in the 1990s, to both reduce stranded costs (by reducing their associated financing cost) and ensure their recovery by utility shareholders.

Securitization typically authorizes a unique form of irrevocable rate order, imposing a surcharge on customers that yields the amount necessary to pay the debt service on the intended bond financing. The right to impose, collect and receive the charges is a form of property interest that is irrevocably transferred to an SPE, which issues the bonds. Customers benefit from the SPE's very low financing costs, which will be less than the utility's weighted average cost of capital. The low interest rate associated with securitized transactions is attributable to the reduced risks perceived by potential investors for bonds that are backed by a predictable revenue stream that is essentially separated from the credit risks of the utility. These reduced risks can translate directly into the highest bond rating attainable for bond issuances, "AAA." Most utilities have credit ratings below AAA. Rating agencies have not treated securitization debt as a borrowing of the utility for purposes of evaluating the utility's capital structure and credit rating, thus preventing the debt from putting further downward pressure on the utility's ratings. As a result, the customers of the utility benefit from the fact that the interest costs of this financing are at very low rates (thus reducing carrying charges) and at the same time the rest of the utility's borrowings (e.g., for normal utility investment in infrastructure) is not made more costly due to the additional debt leverage at the SPE.

Securitization is an attractive alternative to utility self-financing of deferred revenues, although it does entail certain transaction and regulatory costs. In addition, legislation is required to give a state's public service commission the authority to establish the binding rate orders and surcharges that establish the basis for the revenue-producing asset transferred to the SPE.

IV. ALTERNATIVE RATEMAKING APPROACHES

Various ratemaking methods can be used to systematically alter the front-end loading resulting from DOC ratemaking. Some of these methods have been used fairly widely while others have been used selectively, if at all. All of these methods are fully consistent with ratemaking principles (e.g., just and reasonable rates, fair opportunity to recover costs, etc.) if applied properly.

Construction Work in Progress

For many years, it was common practice to include in the rate base an allowance for "overhead" construction costs. Such an allowance included the costs of incorporation; legal, engineering and administrative services; and interest insurance and taxes during construction. With the development of the uniform system of accounts, utilities were required to enter all costs incurred during construction. Interest during construction was capitalized and, when the plant went into service, the accumulated interest was added to the book cost of such plant and the total amount over the useful life of the plant. In 1971, the Federal Power Commission (predecessor to the Federal Energy Regulatory Commission (FERC)) abandoned the term "interest during construction" and substituted "allowance for funds used during construction" (AFUDC) in its system of accounts.[5]

Starting in the late 1960s, costs of both construction and capital began to increase dramatically, and construction periods were greatly extended. As a result, AFUDC accounts became very large. By 1980, AFUDC had increased to more than 50 percent of the electric industry's return on common equity.[6] Since the typical electric utility has a payout ratio in excess of 50 percent, companies were in effect being forced to borrow funds to pay common stock dividends.[7]

Confronted with severe cash flow problems and inadequate coverage ratios, many commissions began to permit all or part of construction work in progress (CWIP) in rate base. In effect, CWIP enables a utility to recover its construction-related financing costs as they are incurred, rather than after the plant is placed into service. By the late 1970s, a majority of the states allowed CWIP in rate base.[8] Actual practices vary considerably, however, as to the amount of CWIP that may be included, and the conditions for its inclusion. FERC permits electric utilities to file for wholesale rates based on the inclusion of up to 50 percent of CWIP in the jurisdictional rate base (subject to a rate impact limit of 6 percent in each of the first two years).[9]

Allowing CWIP in rate base before a facility is in service or allowing a cash return on CWIP are both ways of minimizing the impact on rate levels when a plant is placed in rate base. Absent either of these ratemaking approaches, the total costs of building new plant, plus interest or carrying charges, would have to be

[5] Charles Phillips, *The Regulation of Public Utilities*, Public Utilities Reports, Inc., 1993, p. 354.

[6] Statistics of Privately Owned Electric Utilities, 8. AFUDC "dollars alone often account for 25 to 30 percent of final plant costs, and can add $20 to $30 million for each month near the completion of a project," Charnoff, Nuclear Prudence Audits, 24. Both cited via Phillips, fn. 195.

[7] Phillips, p. 354-55.

[8] See Phillips, fn. 198.

[9] Phillips, p. 355.

accumulated and compounded until the plant enters service and is included in rate base. Hence, allowing CWIP or a cash return on costs incurred during construction is similar to a phase-in plan that gradually spreads the inclusion of costs in rates, though it spreads the pain back in time rather than forward. CWIP spreads the recovery of new costs over a longer period than would otherwise be the case and also eliminates the compounding of carrying costs, which in itself alleviates pressure on the utility's credit ratings. In addition, CWIP allows customers to see a gradual rate increase in a timely way, thereby enabling them to adjust their consumption habits and energy consumption infrastructure. Conversely, AFUDC accounting can magnify very large additions to rate base when the plant enters service, creating a potentially large, sudden increase in rates.

CWIP proved to be a controversial ratemaking approach in the past, and was frequently opposed by consumer advocates and other customer representatives. Following are the objections frequently expressed in regard to CWIP, along with our response to these concerns.

1. **CWIP is inequitable because it forces customers to pay for an asset before they receive any benefits from the asset.** However, ratemaking already is inequitable, even under strict DOC, as straight-line depreciation does not equal economic depreciation, and many operating costs are lagged and/or trued-up. Thus, traditional ratemaking does not lead to a temporally perfect match of costs and rates. Also, it is true that financing costs, if increased due to a utility's weak credit rating during major construction, could have an immediate, adverse effect on all customers. However, if financing costs are reduced with CWIP, then there is a positive impact on customers in that life-cycle present value costs are reduced.

2. **CWIP reduces a utility's incentives to control costs.** However, CWIP can be restricted to a pre-determined budget of prudent and cost-effective expenditures, with any cost overruns at risk.

3. **CWIP prevents used and useful disallowances if a plant turns out to be excess capacity.** However, the used and useful principle arguably is anachronistic in a credit-constrained, highly volatile environment in which significant new infrastructure is needed. CWIP is more likely to foster the right kind of planning discussions before the fact.

Contributions in aid of construction (CIAC) are distinct from CWIP, but they have a similar effect in that some of the costs of infrastructure to serve a customer or a group of customers are contributed by the customer. Sometimes these contributions are loans that are paid back or refunded when the facility enters service. For non-refundable CIAC, the rates charged contributing customers are reduced to reflect the value of their contributions.[10] CIAC participation by customers generally is optional, while CWIP in rate base applies to all customers.

Sale and Leaseback

CWIP, as we saw, reduces rate shock by enabling a utility to recover all or a portion of its construction-related financing costs while the plant is being built, thereby reducing the capital recovery required after the plant enters service. A sale and leaseback agreement is one means of reducing the front-loading of capital recovery after a plant is brought into service, along with possibly reducing the financing costs. The primary motivation for such agreements is to enable the transfer of federal tax benefits related to a certain piece of property between two parties without actually transferring ownership of that property. The lessor is allowed to utilize the federal accelerated depreciation allowances and any other development tax credits on the

[10] *Id.*, p. 17.

property. The expected effect is to allow the lessee to receive a portion of the lessor's tax savings through cash payments and/or reduced rental charges for the use of the property.

Hence, leasing enables firms that may not reliably have sufficient federal tax liability (such as a utility with a major expansion plan) to immediately utilize certain tax benefits to receive at least a portion of those benefits through reduced financing costs implicit in the rental payments. So there are two potential advantages to the sale and leaseback of a power plant: (1) alleviating the rate shock associated with bringing a new generating plant into rate base, and (2) reduced financing cost resulting from a "flow-through" of tax benefits in the lease price. The primary disadvantage of leasing is that the utility does not earn a return on its investment because the asset is not included in the company's rate base.

Sale and leaseback transactions have not been common in the U.S. electric power industry. However, in the 1980s, several utilities consummated sale and leaseback transactions for newly constructed nuclear power plants. A study of sale and leaseback transactions by electric utilities during the period 1978 to 1990 found that most of the transactions are clustered from 1985 to 1987, the period just prior to the effective date of the Tax Reform Act of 1986, a law that reduced the effectiveness of sale and leaseback transactions for utilities. The study's authors concluded that tax considerations appear to play an important part in explaining these transactions.[11]

This study also found that most of the firms engaging in sale and leaseback transactions had low common equity ratios, Value Line safety rankings, and Value Line financial strength ratings, and high proportions of non-cash earnings (AFUDC) relative to industry average levels. These findings are consistent with financial distress explanations of utility sale and leaseback transactions. Sale and leaseback transactions are attractive to financially weak firms, possibly because of the less burdensome covenants associated with lease financing compared with secured borrowing and the preferred position of lessors in bankruptcy.[12] Hence, the desire to mitigate rate shock does not appear to be the primary motivation behind most of the 1980s vintage sale and leaseback transactions.

That said, lease financing provides a means of reducing rate shock, because the revenue requirements typically are levelized over the life of the plant, such that the utility makes level payments over the life of the lease. These lease payments are normally treated as a cost of service and reflected in the utility's revenue requirement. Rates are lower initially, but the discounted present value of the cumulative lease payments is equivalent to the discounted revenue stream that the utility would have received under DOC ratemaking, apart from any cost savings yielded by a flow-through of tax benefits. Hence, sale and leaseback transactions can be viewed as a means of achieving levelized capital recovery for the leased plant, with the potential added benefit of lower costs due to a flow-through of tax benefits.

Trended Original Cost Ratemaking

Trended original cost (TOC) is a form of ratemaking that has been applied to oil pipelines by FERC but which has been used little, if at all, in the electric power industry. TOC and net depreciated original cost are essentially the same except for their treatment of inflation. TOC reflects inflation through an automatic adjustment to rate base, whereas net depreciated original cost reflects estimated inflation in the nominal rate

[11] Krishinan V. Sivarama, *Sale and leaseback transactions: The case of electric utilities*, Quarterly Journal of Business and Economics, September 22, 1995.

[12] *Id.*

of return. This difference between them results in a different timing of the recovery of the cost of equity capital, when inflation exists, over the life of the property. Both methods, however, yield the same discounted earning stream for shareholders.

TOC in the oil industry works as follows. First, TOC, just like net depreciated original cost, requires the determination of an allowed, nominal (inflation-included) rate of return on equity that reflects the firm's risks (its cost of capital). Next, the inflation component of that rate of return is subtracted, to produce the "real" or "inflation-adjusted" rate of return. The real rate of return times the equity share of the rate base yields the yearly allowed equity return in dollars.[13] The equity rate base write-up is derived by multiplying the equity rate base by the inflation factor. That write-up, like depreciation, is written off or amortized over the remaining life of the property, which declines by one year each year.[14]

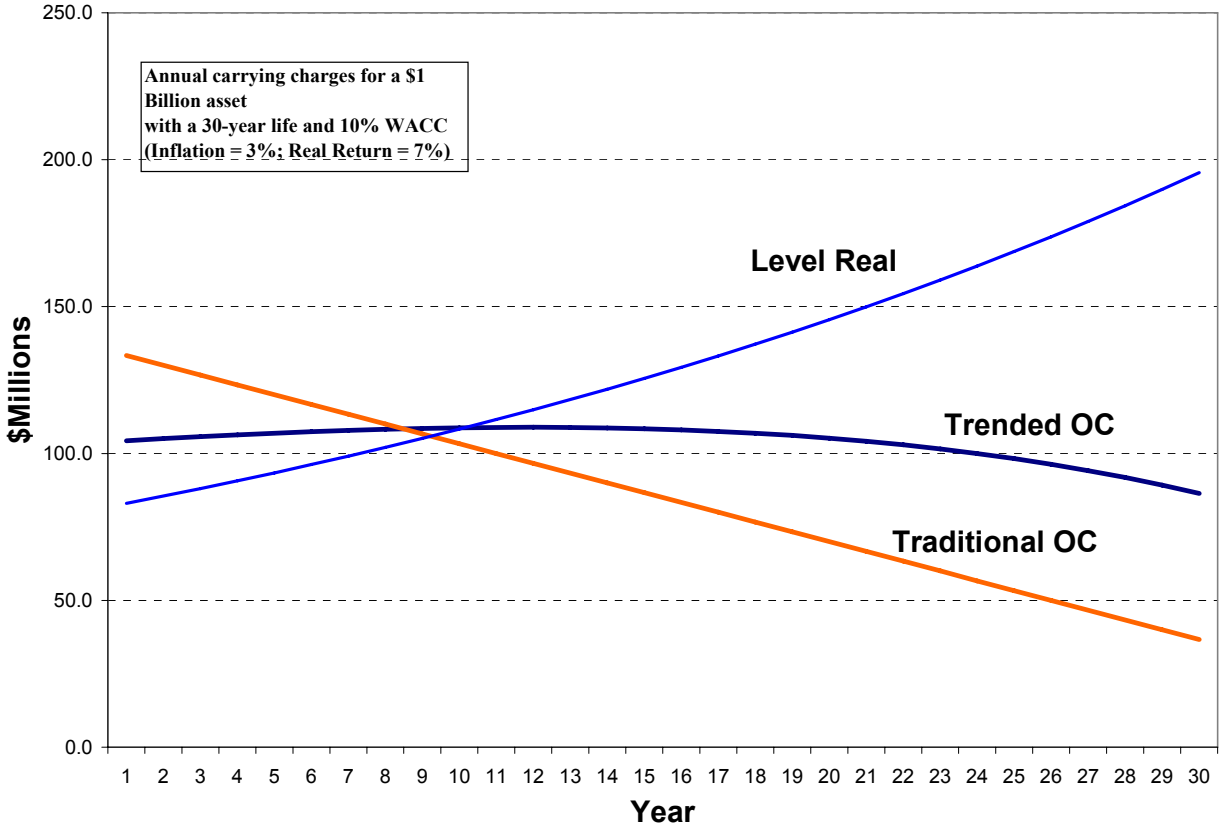
The following example illustrates TOC ratemaking. Assume a new generating plant with an original equity investment of $1,000,000. Also assume that a just and reasonable return on equity would be 11 percent and that 4 percent of that represents inflation. This leaves 7 percent as the "real" rate of return. In its first year of service, the power plant would be entitled to earn $70,000 (7 percent times $1,000,000), and $40,000 (4 percent times $1,000,000) would be capitalized into the firm's equity rate base to be amortized over the life of the property starting in the first year, along with the depreciation on the $1,000,000. If the depreciation life were 20 years, in addition to the return of $70,000, the plant would be entitled to recover, in the first year, $2,000 as amortization ($40,000 divided by 20), $50,000 as depreciation ($1,000,000 divided by 20), its embedded debt cost, and depreciation associated with debt investment. The equity rate base at the start of year two would be $988,000 ($1,000,000 - $50,000 + $38,000). This process would continue over the life of the property until the rate base (assuming no salvage value) hit zero. Unless changed in a rate case, the real rate of return, which should be relatively stable, would be 7 percent each year. The inflation rate would vary as the chosen inflation index varies. Potential inflation indices include a construction price index (such as the Handy-Whitman index) or the U.S. Treasury bill rate.

An important advantage of TOC ratemaking, relative to DOC, is that it reduces the front-end loaded cost recovery associated with the latter. DOC produces front-end loaded cost recovery because the rate base declines over time, causing the firm's allowed return for its equity cost of capital to start high and end low. This means that most of the company's present value equity return is compressed into the early years of its property's life when its rate base is still large. TOC ratemaking, on the other hand, defers utility income until later years by capitalizing the inflation factor into the equity rate base. As time goes on and prices rise because of inflation, the company under TOC can raise its rates to recover the deferred income. Hence, investors receive a higher initial cash return under DOC than under TOC regulation, but a lower cash return when the asset is older. However, the ex ante present values of the cash returns generated over the life of an asset are identical under fair DOC or TOC regulation. The time patterns differ but the values are the same. Figure 2 compares the pattern and timing of capital recovery under TOC to that achieved under DOC. As one can see, TOC leads to a relatively level capital recovery stream until the later years of the asset's operating life. In contrast, levelizing capital recovery in real (inflation-adjusted) dollars leads to back-end-loaded capital recovery.

[13] There is no reason to restrict this to just the equity portion of the rate base, as we explain later in this section. However, this is how FERC has applied TOC ratemaking in the oil industry.

[14] FERC Order Issued June 27, 1985*, 31 FERC ¶ 61,377*. This order established the J&R method of setting rates for oil pipelines.

Figure 2: Comparison of TOC and DOC Pattern and Timing of Capital Recovery



Another advantage of TOC is that it comes closer to duplicating pricing in unregulated industries, in which assets typically depreciate at a slower rate than that which occurs under straight-line depreciation. When inflation is rapid, DOC regulation can lead to consumer prices far out of line with what a competitive firm would charge. The source of the problem is that historical cost accounting does not approximate the value that assets actually have in competitive, unregulated industries. Values based on historical costs can be grossly misleading when inflation is rapid, particularly for long-lived assets. TOC also arguably provides for greater intergenerational equity by providing relatively constant cost of equity capital charges in real terms (adjusted for inflation) to ratepayers over the life of the regulated property. Under TOC, the successive generations of ratepayers will be paying more in nominal dollars, but they are paying in cheaper dollars because of inflation.

A TOC rate base sometimes is incorrectly characterized as "fair value" ratemaking, suggesting regulation as practiced before the *Hope* decision, and as may still be practiced in some states. Fair value typically relied on engineering estimates of replacement cost. TOC, conversely, is consistent with use of historical account-ing costs. Figure 2 illustrates the distinction between TOC and fair value regulation, which estimates the current value of an asset or portfolio of assets at any given point in time. Fair value regulation would lead to a capital recovery pattern closer to that achieved by real levelized capital recovery—the top line in Figure 2. Trending net book value for inflation leads to a much more level recovery pattern than would be achieved through periodic resetting of an asset's value based on its replacement cost.

Some regulators, including FERC, believe that trending the entire rate base will give equity holders an unjustified benefit from a write-up of the portion of the rate base financed by debt. According to this view, equity holders only should be compensated for inflation to the extent that assets are financed by equity. However, we believe that view is mistaken, and that the entire rate base can (and should) be trended, provided only a real cost of debt is allowed. Either approach (i.e., trending the full rate base or just the equity portion of the rate base) can be implemented so as to yield the same life-cycle present value revenues, but with different implications for how readily debt service may be recovered.

If regulators decided to implement TOC, all new assets would be placed in rate base at original cost (as they are today) and trended as described above. However, for existing assets that are currently valued at DOC or some other method, a one-time adjustment would be necessary to arrive at an appropriate rate base to be trended for the future. The starting or transition rate base would have to reflect the capital (i.e., depreciation) that the firm already has recovered under the prior ratemaking regime. When switching ratemaking regimes, regulators should ensure that the transition rate base is established in a way that gives the firm a fair opportunity to earn a return of and on its invested capital, consistent with traditional ratemaking principles. In other words, while a switch to TOC (or any alternative ratemaking method) will change the pattern and timing of cost recovery, a firm should have the same unbiased opportunity to recover its investment as it would have had without any change in ratemaking regimes.[15]

Buy v. Build

Long-term power purchases, either from merchant generators or other utilities, are another way of levelizing the timing and pattern of capital recovery associated with new generating capacity. While the terms and conditions of long-term power contracts can and do vary widely, given the type of product being sold and market conditions, among other factors, the demand charges established in such contracts often are either constant or rise at the rate of inflation (or other pre-determined escalation rate). These contracts, in other words, often have real or nominal levelized capacity payments that result in a timing and pattern of capital recovery similar to that achieved under TOC. Indeed, it is unusual for a long-term power contract to have front-loaded (i.e., declining) capacity payments comparable to that resulting from DOC. So purchasing new generating capacity is another potential means of mitigating the initial rate shock associated with the addition of new assets to the company's cost of service. Indeed, it may be possible to regulate very nuanced capital charges in a purchased power contract, if desired.

Of course, many other factors are taken into account by a utility and its state regulators in deciding whether it is preferable to build new generation capacity or buy long-term firm power from the market. But one possibly overlooked benefit of buying power is that it typically leads to levelized capital recovery without requiring changes in ratemaking methodology. Purchasing also may allow a better matching of capacity to the utility's resource needs, while outright ownership of a large plant may be more "lumpy."

[15] William B. Tye, The Transition to Deregulation: Developing Economic Standards for Public Policies, Quorum Books, 1991.

Summary

There are many financially equivalent ways to recover capital costs, by varying how amortization and returns are scheduled. Moreover, these methods all can be designed so as to give a company a fair opportunity to recover its costs, consistent with traditional ratemaking practice. Some practices, such as CWIP, allow for cost recovery before a plant enters service. Other methods, such as sale and leaseback, foster levelized capital recovery. In the absence of tax benefits, however, the financial effect of sale and leaseback is very similar to that of an outright purchase of long-term, firm power. By taking the inflation component out of the return and placing it in the rate base, TOC yields much smoother capital recovery than that achieved under DOC. While TOC is sometimes viewed as a form of fair value ratemaking, it has the benefit of not requiring engineering estimates of replacement or reproduction cost.

V. PREVENTING FUTURE SHOCKS

The ideal, though unattainable, solution to "rate shock" would be to develop a perfectly timed, dynamically evolving portfolio of both owned assets and power purchases, coupled with a risk management policy that gives a company virtually "bulletproof" protection against large price increases. Of course, there is no fool-proof way of avoiding rate shocks, at least no way that is not prohibitively expensive (such as building so much base-load capacity that the company almost never has to dispatch or purchase gas- or oil-fired generation). A utility can hedge fuel price exposure over a couple of years forward contractually, but the cost of hedges will track rising fuel prices (and fuel price volatility). All utilities are exposed to volatile wholesale prices to one degree or another. Similarly, utilities cannot fully hedge themselves against volumetric risk, weather and other operating risks. In short, there will always be some risk of rate shock, given that certain significant input costs are largely or totally beyond a utility's control.

That said, a utility certainly can meaningfully reduce its exposure to rate shock through effective resource planning and well-designed risk mitigation policies. For example, if a utility is self-building its supply, the possibility of rate shock can be lessened through the construction of smaller assets (which may also have advantages not captured in typical present value revenue requirement (PVRR) analysis, due to their flexibility or optionality). Building smaller assets also allows a utility to better match supply with load growth.

Similarly, for utilities that rely primarily on power purchases, staggered and laddered procurement will have lower rate shock risk than procurements that require a utility to seek 100 percent of its power supply at one time. The latter approach obviously exposes the utility to the risk that it might inadvertently procure all of its power supply in an unfavorable (i.e., high-priced) market. In addition, procuring all supply at once may make it harder for a utility to get a good price, to the extent the large purchase "moves the market" and potentially excludes small suppliers who cannot fill a significant portion of the utility's requirements. This is one reason why many retail-access states have now implemented a "laddered" procurement approach for standard offer or provider of last resort (POLR) service. Indeed, some states that initially directed their utilities to procure 100 percent of their POLR requirements at one time have subsequently gone to a staggered procurement approach, with overlapping contracts (e.g., multiyear, overlapping contracts with 33 percent of the necessary supply procured at a time).

Fuel and technology diversification is another potential means of reducing the risk of rate shock, with the caveat that diversification, in and of itself, does not necessarily reduce price risk cost-effectively. The problem is that resource diversification, in the context of an electric utility, is very different than the concept of financial diversification applied to portfolio management.[16] All financial assets are substitutes for each other, subject to their risk-return characteristics. This is not true for utility assets, which are much more complex and multidimensional in their service attributes and much less readily substitutable for each other. The differences among generation asset types and power purchase contracts often cannot be simply reduced to monetary dimensions along which they can be freely interchanged. Moreover, portfolio management in financial markets presumes free disposability of assets, which does not apply to electric utility assets such as

[16] See *Utility Supply Portfolio Diversity Requirements*, prepared by The Brattle Group for Edison Electric Institute, December 2006.

generation plants and power purchase agreements. Utility diversification for its own sake may actually raise costs, rather than just smooth them (as would be the case for financial assets).

Until one is very specific about the type of "return" (benefit) of interest (among many possible types of benefits and time frames for their realization—near-term rates, annual company net cash flows, the PVRR of all generation assets, etc.), one cannot begin to determine whether diversity would somehow enhance its risk profile. That said, there are ways in which some portfolio management ideas can be usefully borrowed by utilities. In particular, it is possible for utilities to use portfolio management to a greater degree when utilities primarily rely on power purchase agreements, because these are financial instruments. The industry already uses most of the directly applicable techniques from financial portfolio management in managing purchase power portfolios.

Finally, demand-side resources (including both conservation programs that reduce overall consumption and load management programs that reduce customer demand during peak periods) are another means of reducing the risk of rate shock. Demand-side management (DSM) is a flexible resource that can be added in small increments to track growing load requirements. Load management programs can enable a utility to significantly reduce its exposure to expensive gas- and oil-fired generation. In addition, by reducing energy usage, DSM also helps reduce the cost and risk associated with environmental compliance. There is increasing discussion of a need for CO_2 regulation to mitigate global climate change. If and when such regulation is imposed, it is likely to entail a protracted period of gradual rate increases, against which conservation may be the best resource (economically and environmentally).

VI. CONCLUSION

The electric utility industry has entered an era of rising input costs, forcing many utilities to seek rate increases. In some cases, the requested rate increases are substantial, particularly in retail-access states in which rates have been frozen or capped at below-market levels for several years. The move to market-based rates and associated large rate increases is causing some regulators to consider methods of deferring or phasing in the approved rate increase.

We noted that traditional DOC regulation practiced by most state regulators leads to front-end-loaded capital recovery, which exacerbates the rate impact associated with a large new asset. Various ratemaking methods can be used to change the timing and pattern of capital recovery in a way that reduces the near-term rate impact associated with a new asset. CWIP can be used to recover the financing costs associated with a new power plant while it is being built, thereby reducing the plant's associated revenue requirement once it is placed into service. Annual capital recovery can be held constant or "levelized" through use of TOC, a sale and leaseback agreement, or other ratemaking methods.

For large rate increases spurred by power purchase costs, rather than new assets, a rate deferral coupled with securitization can be used to both defer cost recovery and reduce the total increase in needed revenues. Securitization reduces the risk of cost recovery and therefore enables funds to be borrowed on favorable terms, more favorable than the utility's weighted cost of capital. This is what reduces the revenue requirement.

However, a key criterion for the legitimacy of all rate deferral or alternative ratemaking methods is that they should hold the utility financially harmless, i.e., the discounted present value revenue stream provided under the rate deferral or alternative ratemaking approach should be identical to the discounted present value revenue stream provided under traditional ratemaking, apart from any savings provided by securitization or sale and leaseback. If this is not the case, these mechanisms ultimately will fail, by undermining the financial health of the utility and reducing its financial flexibility such that it has few or no good options.

A utility can reduce, though certainly not eliminate, its exposure to rate shock through its resource planning and risk management practices. Risk can be reduced through laddered power purchases, construction of relatively small assets that facilitate optionality and flexibility, and pursuit of cost-effective demand-side resources that, among other things, reduce exposure to expensive on-peak generation and environmental compliance costs.

In short, there is no magic bullet to solve the rate shock problem. But there are sound ratemaking and planning approaches that can provide near-term relief and reduce the possibility of rate shocks occurring in the future.

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REQUESTOR NAME: BCOAPO

Information Request No. 3.1 to COPE
British Columbia Hydro and Power Authority Amended F2012 to F2014 Revenue Requirements Application

3.0 Topic: Energy Deferral Accounts

Reference: Exhibit C2-16, Recommendation 4, pages 7 and 8.

3.1 BCOAPO's understands that BC Hydro optimizes its heritage hydro facilities over a multi-year period rather than on an annual basis. How should the Commission in COPE's view take this into account when determining recovery of the variances collected in the Heritage Energy deferral account?

Response:

In its workshop presentation (Exhibit B-13) BC Hydro states that it uses the same models for operational and forecasting purposes, and that BC Hydro's revenue requirements are informed by the long-term models. It appears that the variances collected in the Heritage Energy deferral account are variances from the same multi-year optimization. This being the case, they should ideally be reflected in the cost of service of the year in which the energy to which they relate was delivered to customers, or failing that, in as short a time period thereafter as practicable.

REQUESTOR NAME: BCOAPO

Information Request No. 3.2 to COPE
British Columbia Hydro and Power Authority Amended F2012 to F2014 Revenue Requirements Application

3.0 Topic: Energy Deferral Accounts

Reference: Exhibit C2-16, Recommendation 4, pages 7 and 8.

3.2 If the energy cost variances were dealt with as indicated for California, it would result in significant rate volatility based on recent water inflow history. In addition, if COPE's Recommendation 7 were implemented, the volatility would fall particularly hard on smaller residential customers. Is rate volatility a concern in COPE's view? Please comment.

Response:

COPE recommendation 7 was "[T]hat the Commission reconsider the use of the rider methodology to recover energy deferral amounts" and was intended to flag a potential issue if BC Hydro's Tier 2 rates ever reflected the true marginal cost of supply.

In its Certificate of Public Convenience and Necessity application dated February 22, 2011 for the Ruskin Dam and Powerhouse Upgrade Project, BC Hydro estimated its marginal cost of supply as follows:

> " BC Hydro evaluated the economic consequences of undertaking the Project or any of the Decommissioning Alternatives by reflecting the weighted value of firm energy using the Clean Power Call-based $129/MWh (F2011$) and non-firm energy at $50/MWh, and the value of capacity using the Revelstoke Unit 6-based UCC of $55/kW-year (F2011$)" (Application at p.3-18).

This suggests that the marginal cost of supply for a residential customer, after factoring in incremental transmission costs and line losses would be in the range of 15 cents per kWh, while Tier 2 residential rate is presently 10.19 cents per kWh plus the DARR of 5% for a total of 10.70 cents per kWh.

The question, as posed, refers only to smaller residential customers. On the assumption that such customers find themselves in Tier 1 most if not all of the time, if the DARR is applied to Tier 1 consumption only then the impact on the Tier 1 and the Tier 2 consumption will be different. It is not possible to determine whether the impact on smaller customers will be "particularly hard", because one cannot predict whether or when the Commission will direct BC Hydro to move Tier 2 prices to the "new" avoided cost, where the next avoided cost would move to in the meantime, and how the Commission would direct BC Hydro to allocate the increases in its revenue requirements between the two tiers. In addition, the issue of how the cost of the new meters will be allocated to customer classes has to be resolved. If the Commission decides that the cost will

be allocated to residential customers on a per meter basis (presumably by increasing the daily Basic Charge), then the impact would presumably fall harder on customers who used less.

The question suggests that recent water flow history has been volatile. I cannot comment on whether it has or not. What goes into the deferral accounts are variances from the volumes and costs of energy contained in an application filed with the Commission by BC Hydro. These volumes and costs are typically updated by BC Hydro, which should limit the variances - certainly in the early part of a test period.

The issue becomes whether volatility might be better addressed by allowing debit variances to build up in the energy deferral accounts until a great water year comes along and flushes the debits away. That was the thinking back in 2003. Since that time the factors that drove this assumption have changed considerably: the US Northwest is in oversupply largely thanks to the recession, the price at COB is down due to the market price of natural gas and to the impact of recently commissioned wind projects, the Canadian $ is much stronger and BC Hydro's operational flexibility has been significantly hampered by the volumes of intermittent energy it is obliged to take and pay for.

REQUESTOR NAME: BCOAPO

Information Request No. 4.1 to COPE
British Columbia Hydro and Power Authority Amended F2012 to F2014 Revenue Requirements Application

4.0 Topic: Recommendation 6

Reference: Exhibit C2-16, pages 10 and 11.

4.1 BCOAPO understands that BC Hydro takes a portfolio approach that includes short term debt, long term debt and financial derivatives that could include the swapping of fixed and variable interest charges in an effort to minimize borrowing costs and manage interest expense volatility. The borrowings are treated as a common source of revenue to fund both long term and short term assets.

What interest rate allocation should be applied to short term asset deferral accounts when BC Hydro does not include enough short term bonds/Commercial Paper in its debt portfolio to fund all of the cost of short term deferral accounts?

Response:

It is not clear what the question means by "when BC Hydro does not include enough short term bonds/Commercial Paper in its debt portfolio to fund all of the cost of short term deferral accounts?"

COPE put a series of IRs to BC Hydro on this subject (COPE 2.75 and 2.76), to which BC Hydro confirmed that its short term debt balance was forecast to grow from $836.5 million at the end of F2007 to $4,273.1 million at the end of F2014. At the same time its "cash" deferrals (by which it meant costs which it has incurred in cash rather than made provision for) were forecast to grow from $359.6 million at the end of F2007 to $3,543.8 million at the end of F2014. (Exhibit B-25, COPE 2.75-6)

It seems clear that BC Hydro has financed its deferred charges with the Province's Commercial Paper (CP) program, and this being the case COPE concludes that future customers should not be asked to pay higher carrying charges that the cost of the CP program.

REQUESTOR NAME: BCOAPO

Information Request No. 5.1 to COPE
British Columbia Hydro and Power Authority Amended F2012 to F2014 Revenue Requirements Application

5.0 Topic: Recommendation 6

Reference: Exhibit C2-16, pages 10 and 11.

5.1 Presently the deferral accounts in total have a large positive balance. Applying a lower interest charge to these positive balances would, all else being equal, quickly reduce the incentive to reduce the positive balances. Please comment.

Response:

The question seems to suggest that those with mortgages with a low rate of interest have less incentive to pay off their mortgages than do those with mortgages with a higher rate of interest. COPE's recommendation addresses the need to reduce the amount of costs deferred by BC Hydro and to ensure that the customers who get to pay the deferred costs in their rates are not paying interest compounded at a rate that bears no relation to the cost of carrying the amounts deferred. In other words, BC Hydro's current practice compounds (excuse the pun) an already serious problem.