

*Resource Planning and Procurement in Restructured
Electricity Markets:
Regulatory Trends and Issues*

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“Capital can and will come back to this industry, assuming that a solid and workable regulatory framework is established and financial discipline of the various players is adhered to.” – Richard Kaufman, First Vice President & Manager, Credit Lyonnaise, testifying at FERC’s open hearing, Capital Availability For Energy Markets, January 16, 2003. (FERC Docket No. AD03-3-000)

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1.0 Executive Summary

The California “meltdown” of 2000 and 2001 has sensitized investors and rating agencies to the risks associated with “resource procurement prudence” (i.e., the potential for distribution utilities to be denied recovery of wholesale supply costs). This sensitivity has contributed to the loss of investor confidence, and the contraction in liquidity, currently being experienced in the electric utility sector.

This paper has been developed to focus recent state reforms intended to help restore investor confidence by increasing the certainty of regulatory planning and approval processes. It includes a set of principles which EEI members believe are appropriate to guide policy makers in approaching reform.

Recent state precedent involving resource procurement are documented in Appendix A. At least four key trends are evident, as follows:

1. States are reforming regulatory planning and approval processes to provide increased certainty. This reflects a recognition of the linkage between regulatory certainty and access to new capital at reasonable rates: that to ensure needed new investment in generating capacity and infrastructure, and to preserve utilities’ ability to procure power at wholesale, utilities need to have a reasonable assurance that costs will be recovered timely in regulated rates. At least five approaches/models are reflected in recent precedent, as follows: (1) up-front definition of *standards and criteria* for regulatory acceptance (CA, MT); (2) up-front review and approval of *resource plans*, including risk-management strategies, with a presumption that costs incurred to implement an approved plan are prudent (CA, CO, ID); (3) pre-approval of procurement contracts (CA); (4) use of a *competitive RFP* (request for proposal) process to demonstrate the reasonableness of proposed projects (LA); and (5) up-front determination of *rate treatment* to be accorded a proposed rate based facility in manner that is binding on future commissions (IA). (Section 3.1)

2. States are addressing the need for Local Distribution Companies to hedge wholesale gas supply costs. States have enunciated principles to guide hedging; and in some cases, have provided up front review and approval of hedging contracts. Key precedents identified include decisions in Arkansas, Kansas, North Carolina, Oklahoma, and Virginia. This suggests that electric distribution companies will find support for the recovery of hedging costs as well. (Section 3.2)
3. States are defining criteria for evaluating the prudence of wholesale procurements by distribution utilities, both gas and electric. In the aggregate (no PUC has used them all) these criteria emphasize diversification of supply, having an explicit risk management strategy, and using a competitive RFP (Request for Proposal) process to procure resources. Where hedging is concerned, additional criteria include the use of pre-approved types of hedging instruments, limiting forward purchase commitments to forecast loads, demonstrating that financial controls are in place to prevent inappropriate hedging activities, and having programs to educate customers regarding the outlook for prices in the region and rate-stabilized service options available to them. (Section 3.3)
4. Some states are using performance-based regulatory mechanisms to encourage utilities to minimize the cost of purchased resources. In some cases, commissions have given up the right to conduct prudence reviews. Key examples include California, Oregon, and Washington state. (Section 3.4)

The issues to be faced in reforming regulatory policies and procedures related to resource procurement are discussed in Section 4.0. These involve *regulatory commitment* - how to balance the investor's need for certainty, with the consumers' need to be protected against poor utility performance in managing resource costs; *risk management* – how best to manage resource risks in a given utility; how to exercise appropriate regulatory oversight and control, recognizing that even superior management strategies are not perfect or full proof, and do entail incremental costs; and how to treat the new resource-related risks in a cost of service framework; *least cost planning* – how to strike an appropriate balance in the utility's resource mix, given the many objectives for resource planning, and the many constituencies, and agendas, involved; and *stakeholder involvement* -

how to involve key stakeholders in the planning and approval process while maintaining forward progress and preserving system reliability.

A set of six principles appropriate to guide public policy in this area are described in Section 5.0. These principles reflect an evolving consensus among EEI members about the need for regulatory reform, and about the desired attributes of such reform. In briefest form, the six principles are as follows:

1. Regulatory certainty is an essential pre-condition for needed new investment in energy infrastructure at reasonable cost.
2. Consumer exposure to volatile wholesale markets can be minimized through risk management.
3. Guidelines for meeting resource requirements should reflect market conditions and balance state, regional, and consumer needs.
4. Stakeholders should be engaged in the review of plans to meet resource requirements, including new infrastructure investments, needed to ensure electricity supply adequacy.
5. The reasonableness of utility decisions must be judged on the basis of facts known at the time that the decision was made, not on the basis of “perfect hindsight.”
6. Resource planning and procurement policies should be guided by the need to provide adequate, reliable, and economically efficient supply services to consumers.

Appendix A contains abstracts of 19 PUC decisions (and two statutes) in 17 states during the period December 4, 2000 through October 24, 2002. These decisions involve the treatment of procured power costs, hedging activities by gas LDCs, and the design of processes for up-front approval of resource strategies and/or costs of electric utilities.

2.0 Regulatory Trends:

Recent precedents (Appendix A) reflect progress already being made in containing regulatory risk at the state level. At least four trends are apparent, as follows:

2.1 Reforms To Increase Regulatory Certainty

The California “meltdown” of 2000 and 2001 has been a wake-up call for policy makers around the Country. The sight of California’s two largest utilities insolvent and unable to procure power from third parties (i.e., because the utilities were not permitted to recover deferred power costs in rates) has provided an indelible lesson about in the linkage between regulatory certainty and private investment. In response, a growing number of states (including California) are moving to restore investor confidence by implementing new regulatory processes designed to provide greater certainty and predictability regarding cost recovery.

In California, a newly “closed” state¹, the Governor signed Assembly Bill No. 57 on September, 2002, which directs the PUC to approve up-front standards and criteria for judging the reasonableness of utility procurements; and by implication, associated costs.² These standards and criteria are to be defined in procurement plans which utilities file with the Commission. The PUC can redirect plans, but once it has approved a plan, procurements made to implement the plan are to be approved *without reasonableness review*, provided they meet the standards and criteria defined in the plan. AB 57 also directs the PUC to use certain rate mechanism to ensure timely cost recovery, and establishes numerous other requirements for what is in procurement plans, including the use of portfolios to diversify supply. See Appendix-3 for the details.

¹ The CA PUC suspended direct access on September 20, 2001, pursuant to California Assembly Bill 1x. See Decision 01-09-060. (www.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/9812.PDF)

² See Appendix-3.

Prior to AB 57, the California PUC adopted an interim procedure to provide up-front prudence approval of procurements made by utilities through December 31, 2002. This interim procedure combined stakeholder involvement with competitive RFP (request for proposal) procurement; and unlike AB 57, it provided for an affirmative PUC vote specifically approving proposed procurement contracts. Such votes were dispositive of any prudence issues, unless the utility misrepresented or omitted material facts, or was imprudent in its performance under the contract(s). (See Appendix-5 for details)

In Colorado, a “closed” state, the Commission adopted revised least cost planning rules in May, 2002 which provide up-front prudence review. If the record contains sufficient evidence (utilities file resource plans every four years), the Commission will specifically approve incremental needs, plans for acquiring resources, and components of a related RFP. A Commission decision specifically approving the components of a utility’s plan creates a presumption that utility actions consistent with that approval are prudent. (See Appendix-8 for details)

In Idaho, another closed state, the Commission approved a settlement in August, 2002 that lowers regulatory risk for Idaho Power Company by defining a risk-management strategy for the Company. The settlement defines risk “tolerances” (i.e., maximum amounts of risk the Company will bear from three sources: Tier 1 – changes in the Company’s load and wholesale market prices, Tier 2 – changes in hydro availability, Tier 3 – wholesale prices declining below levels at which the Company has agreed to buy power). As the Company manages to these tolerances, it will notify the Commission and staff, in confidence, when it enters into forward monthly contracts whose price exceeds a pre-defined Market Review Trigger. This is to provide early consumer price signals (i.e., by adjusting retail rates) in a rising market. (See Appendix-13 for details)

In Iowa, a “closed” state, legislation was passed in July of 2001 authorizing the Iowa Utilities Board to specify the ratemaking treatment to be accorded new facilities *before they are constructed or leased*, and giving utilities the discretion to decide whether they want to build on those terms, or not. The law directs the Board to publish orders, pursuant to a contested rate proceedings, which specify how proposed projects would be treated for ratemaking purposes. Once the Board publishes an order, it is *binding on future Boards*; and if the utility does not like the rate treatment, it is free to withdraw its application. The Act does not apply to purchased power contracts. Nor does it apply to all facilities; only projects

proposed by regulated utilities, which will be owned, or leased, in Iowa, and which meet certain other requirements. (See Appendix-9 for details.)

In Louisiana, a “closed” state, the Public Service Commission adopted a new planning process in April, 2002 which combines competitive procurement and stakeholder involvement, with a certification process. The utility initiates the process (Phase-I) by filing information preparatory to issuing an RFP (needs, self-build cost, etc.). The utility can request that self-build cost estimates be kept confidential. After reviewing its filing with staff and other interested parties, the utility issues the RFP, evaluates the bids received, and selects a winner. In Phase-II, the utility applies formally for a CNN, using the results of Phase-I to demonstrate the reasonableness of the request. (See Appendix-17 for details)

In Montana, an “open” state, Northwestern Energy (formerly Montana Power Company) negotiated a set of guidelines with the MT staff in the fall of 2002 that define reasonableness criteria for procurements made to supply Default Supply Service (DSS). The Guidelines do not define a specific planning and approval process, but address practices related to (1) utility planning in a market environment, (2) affiliate transactions, and (3) documentation. The Guidelines are premised on the use of portfolio management, and on the use of sophisticated computer-based analyses to evaluate and manage relevant risks (e.g., through scenario testing, and the use of multivariate bid evaluation procedures). The Guidelines require specific procedural safeguards for procurements from affiliates; and, anticipating annual cost recovery filings, “suggest” that such filings should be supported by extensive documentation (e.g., describing analyses used to construct and optimize portfolios, and reflecting input from a Technical Advisory Committee). (See Appendix-19 for details)

2.2 Support For Gas Hedging

In the last two years, stimulated by the rapid run-up in natural gas prices during the winter of 2000-2001, a growing number of states have addressed the need for Local Distribution Companies to hedge wholesale supply costs. These states have enunciated principles to guide hedging; and in some cases, have provided up front review and approval of hedging contracts. This suggests that it may be appropriate for electric utilities to hedge supply costs as well.

In Arkansas, the Public Service Commission *required* LDCs to use hedging instruments in a June, 2001 order that promulgated principles to guide their reasonable use.³ These principles emphasize diversification to balance reliability, reduced volatility and reasonable price. The Commission explicitly endorsed the recovery of hedging costs, including fees and other compensation costs, via fuel adjustment mechanisms. Companies must submit supply portfolios, including hedging strategies, for annual prudence reviews; and are required to maintain extensive records of their hedging activities. Specific record keeping requirements include: an overall risk management plan, a policy and procedures manual, a demonstration of corporate tracking and reporting internally, and evaluation metrics by which program performance can be judged. Utilities also are required to maintain accounting records that track hedging fees, gains, and losses that flow through fuel adjustment mechanisms; and how hedging transactions are reported for tax purposes. (See Appendix-1 for details)

In Kansas, the State Corporation Commission provided in February, 2002 up-front approval for the hedging program of Kansas Gas Service Company. The Commission approved a settlement agreement which defines a hedging strategy, and a hedging budget, for the 2002-2003 heating season; and provides for recovery of associated costs in rates. The hedging strategy is classified as confidential commercial information, but Staff affirmed that it is "...consistent with the public's preferred risk management strategy..." The Company is to provide monthly reports to the Commission detailing the status of the program, and to meet with Staff and the Utility Ratepayer Board each month, or as otherwise requested, to discuss the program. (See Appendix-13 for details)

In New Jersey, the Board of Public Utilities agreed in a March, 2002 order that new gas procurement guidelines are needed to deal with volatile wholesale markets, and directed LDCs to submit hedging programs for review by the Board. (See Appendix-19 for details)

In North Carolina, the Utilities Commission in February, 2002 strongly encouraged LDCs to look at hedging by ordering that they describe their hedging strategies during annual prudence reviews, or explain why they have elected not to hedge. Following the 2000-2001 heating season the Commission looked into

³ see Appendix-1.

hedging, and recently found that hedging was not being used in the state because of prudence concerns. To overcome these concerns, the Commission issued an order affirming that if an LDC uses hedges, premiums and other transaction costs are appropriately flowed through the state's purchased gas adjustment mechanism. As to prudence, the Commission said: "While the Commission cannot accept pre-approval, it acknowledges the UDCs' concern over the fairness of hindsight reviews. Several parties commented that the prudence of hedging decisions should be judged based on facts known at the time the hedging decision was made...The Commission emphatically agrees with these comments. The review of the prudence of hedging decisions, including both any hedging plan and any decisions made during the implementation of such a plan, should be conducted on the basis of facts known at the time the decision to hedge (or not to hedge) was made and not on the basis of the outcome of the hedging decisions." (See Appendix-18)

In Oklahoma, the Commission issued policy guidelines in July, 2001 regarding the reasonableness of hedging strategies employed by Oklahoma Natural Gas Company. These principles emphasize diversification of supplies, complete record-keeping, customer education (i.e., regarding the outlook for prices in the coming heating season and the existence of levelized or average payment plans), and the importance of keeping staff closely informed on procurement options available and decisions the Company takes to mitigate price volatility. The principles also provide for annual prudence review of the Company's supply portfolio and "risk management plan." The Commission provides for the recovery of hedging costs through the company's Purchased Gas Adjustment mechanism. (See Appendix-21 for details)

In Virginia, the State Corporation Commission issued an order in September, 2001 approving the use of three kinds of hedges through the 2005-2006 heating season (i.e., price caps, price bands, and fixed price hedges), and requiring LDCs to file an annual report by June 30 each year detailing hedging activities. Annual reports are to describe the hedging instruments used in the previous heating season, the costs incurred to provide counter party compensation, and the calculation of gas volumes the company is planning to commit to take in the coming season. By June 30 of 2005 companies must apply for approval to change their hedging programs (i.e., the volumes hedged, or the kinds of hedges employed). This Order also provides guidance regarding the appropriate accounting treatment for hedging transactions.) (See Appendix-24 for details)

2.3 Defining The Elements Of Procurement Prudence

The regulatory precedents summarized in Appendix A suggest some of the criteria that commissions might apply in evaluating the reasonableness of resource procurements. These include the following:

Diversification – Whether the procurement was part of a diversified supply strategy. The Arkansas and Oklahoma Commissions cite diversification as a principle that gas LDCs should follow in hedging gas supply costs. Arkansas defines it as “...an appropriate combination of different types of gas purchase contracts and/or financial hedging instruments...” Montana’s Resource Planning and Procurement Guidelines cite as objectives “Assemble and maintain a portfolio..,” and “Maintain a diverse mix of power supply resources/contracts...;”

Risk Management – Whether the company documented an explicit risk management strategy, and whether the procurement was consistent with such strategy. Arkansas requires LDCs to file supply portfolio plans detailing contracting and/or hedging objectives. California has directed each utility to work with a Procurement Review Group to develop a plan for stabilizing and minimizing retail rates during the transition period. Kansas approved a Kansas Gas Service Company settlement that specified a risk management strategy (the details of which were classified as confidential). North Carolina ordered LDCs to describe their hedging policies and practices during annual prudency reviews. Oklahoma cites among eight policy principles LDCs should use in hedging that they should develop a risk management plan. Montana’s Guidelines contain an entire section on risk management and mitigation, which requires “...the evaluation of uncertainty and managing and mitigating risks associated with the electricity supply market and service characteristics of default supply load;”

Competitive Procurement – Whether the procurement was made through a competitive bidding process. California’s interim procurement process provides that utilities procure incremental resource needs through competitive bid. Kansas Gas Service Company’s hedging program provides for an RFP process to procure services for the management and use of the Company’s storage and transportation facilities. Louisiana’s planning process envisions that utilities will procure

incremental resources through competitive bid. Montana's Guidelines indicate that "...Northwestern Energy should use competitive solicitations as a preferred method of procuring default supply resources" from the market.

Where hedging is concerned, the precedents suggest two more reasonableness criteria, as follows:

Hedging Types – Whether the hedging instruments used were of the kinds approved for use in the jurisdiction. Virginia has defined three kinds of hedging instruments which the Washington Gas Light Company is authorized to use through 2005-2006 heating season (i.e., price caps, price bands, fixed price hedges); and

Forward Commitments – Whether the volumes of power committed to in forward contracts exceed forecast loads. Nevada found that it was imprudent for Nevada Power Company to have purchased power in excess of its on-peak and off-peak loads. Virginia requires Washington Gas Light Company to report by June 30 each year the maximum daily take volumes they plan to use in negotiating hedges for the coming heating season.

The precedents also suggest several design features useful in developing prudence-assured planning and approval processes. These include the following:

Public Review - The involvement of constituencies that traditionally intervene in utility cases to achieve their buy-in to procurement strategies and contracts. California's interim approval process requires each utility to work with a Procurement Review Group to identify incremental needs, and develop and evaluate RFPs. The settlement agreement that provides up-front prudence approval (including rate treatment) for Kansas Gas Service Company's hedging activities was negotiated among the Company, Staff, and the Citizens' Utility Ratepayer Board. Louisiana's up-front approval process involves Staff and "other qualifying participants" in reviewing the RFP and supporting filings before it is issued, and in evaluating bids received in response. Montana's Guidelines directs Northwestern Energy to work with a broad-based Technical Advisory Committee;

Regular Reporting - Periodic reporting to the applicable regulatory authority concerning procurement strategies, and progress in implementing them. Arkansas requires utilities file supply plans annually. Kansas Gas Service Company's

settlement provides for monthly progress reports. The Company also undertakes to meet with Staff and the Citizens' Utility Ratepayer Board monthly, or as otherwise requested. North Carolina requires LDCs to file hedging strategies annually. New Jersey has required LDCs to submit hedging programs for review, although it apparently has not (yet) established annual, or other regular, reporting requirements. Oklahoma requires LDCs to file annual gas supply plans, and to keep Staff "closely informed." Pennsylvania requires electric distribution companies to submit annual reports detailing extensive information related to supply planning. Virginia requires LDCs to file annual reports describing the status of hedging activities. Montana's Guidelines require Northwestern Energy to make annual default supply tracking filings with the Commission;

Corporate Controls - Internal procedures to ensure that hedging activities are appropriately focused and do not threaten the solvency of the corporation. Arkansas requires LDCs to document the following: (1) utility-specific hedging goals and guidelines, (2) a Policy and Procedures Manual, (3) procedures for tracking and reporting to management and the Board of Directors, (4) a methodology for measuring hedging program performance, (5) accounting information that tracks fees, gains, and losses that have flowed through the Purchased Gas Adjustment mechanism, and (6) evidence that hedging transactions have been accounted for in accordance with Financial Accounting Standards Board and Internal Revenue Service requirements. Oklahoma requires LDCs to maintain complete records for any hedging programs they elect to use;

Customer Education - Information campaigns to educate customers regarding the outlook for wholesale prices in the region, and service options they may have involving stabilized rates. Arkansas encourages LDCs to convey to customers a good-faith estimate of gas prices for each upcoming winter heating season. Oklahoma requires the same, plus notification of levelized billing or average payment plans available to customers;

2.4 Developing Incentive Mechanisms To Treat Purchased Power Costs

A final trend involves the use of performance-based regulatory (PBR) mechanisms to provide incentives for utilities to minimize purchased power costs.

In some cases, commissions have explicitly given up the right to conduct prudence reviews in adopting such mechanisms.

In California, AB 57 allows (but does not require) utilities to include incentive mechanisms in their procurement plans. The statute provides for “An incentive mechanism, if any...is proposed, including the type of transactions to be covered...their respective procurement benchmarks, and other parameters needed to determine the sharing of risks and benefits.”⁴ As of this writing, an incentive proposal the California PUC is pending

The San Diego Gas & Electric Company in February, 2003 proposed an incentive mechanism tied to the unit cost of procured energy resources, including the cost of risk management. A unit cost benchmark is defined as the forecast cost of all procured electric resources, divided by forecast load and ancillary services (mWh). The load forecast is adjusted for the expected effects of energy efficiency (“negawatts”), and expected sales of surplus power. Actual costs would be compared to the benchmark annually, and savings, or overages, would be shared between customers and shareholders according to a set of symmetric collars. Savings and/or overages would be flowed through a balancing account mechanism.⁵

In Oregon, the Public Utility Commission approved in August, 2001 a Power Cost Adjustment mechanism, which creates an incentive for Portland General Electric Company to reduce purchased power costs relative to a define baseline.⁶ Unlike the earlier polices, Oregon has not explicitly foregone the right to conduct prudence reviews. Also, Oregon’s mechanism accounts for changes in revenues as well and cost (i.e., Power Cost Variance is defined as the difference between actual and base net variable power costs, *less the difference between actual and base energy revenues*). Baselines were determined in a rate case. The first \$28 million in overages or savings is absorbed 100% by the Company. Variances over \$28 million are shared with customers in increasing proportions

⁴ California Assembly Bill No. 57, Sec. 2. (b) (6).

⁵ Based on slides shared by Joe Kloberdanz, Manager - Electric Case Management, California Regulatory Affairs, San Diego Gas & Electric / Southern California Gas Company. Note that an earlier generation procurement incentive, the Electric Generation & Dispatch Mechanism, was approved in 1992. (Ref. CA PUC Docket U902, October, 1992.)

⁶ see Appendix-22.

(i.e., from 50% for variances from \$28 - \$38 million, to 95% of variances over \$200 million).

In Washington, the Utilities and Transportation Commission approved in June, 2002 an Energy Recovery Mechanisms (ERM) to treat purchased power costs incurred by Avista Utilities (formerly Washington Water Power).⁷ Like Oregon, the Washington Commission does not address prudence forbearance. And like Oregon, the ERM mechanism accounts for changes in revenues as well as cost. The first \$9 million in overages or savings is absorbed 100% by the Company. 90% of variances over \$9 million are booked to a deferred balance for recovery (or refund) in rates. In approving the ERM, the Commission noted that it is intended for “ordinary” as opposed to “extraordinary” variations in power cost, although it was not clear how the Commission meant to distinguish to two.

⁷ see Appendix-25.

3.0 Issues Presented

The reform of regulatory planning and approval processes for electric utilities can be expected to raise a number of key issues, for regulators as well as for utilities.

3.1 *Regulatory Commitment*

The fundamental issue is whether regulators should commit to the recovery of costs before they are incurred. On the one hand, this is needed to ensure adequate investment in new energy facilities, and allow utilities to access new capital on reasonable terms (i.e., by reducing perceived regulatory risk); all of which seems to be in the public interest. On the other hand, the function of regulation is to ensure that rates are “just and reasonable,” which means not writing utilities a blank check, but making sure they exercise prudence judgment and manage their business reasonably. Recent precedents suggest that the way to handle this seeming contradiction may be for regulators to focus on developing a reasonable resource strategy, and commit to the resource plan/strategy, rather than to specific costs. By creating an explicit assumption that cost incurred to implement approved resource plans are prudent, the scope of potential prudence inquiries is narrowed (so regulatory risk is lowered), and commissions retain the ability to protect rate payers from poor management performance in executing approved plans. Periodic reporting (by the utility to staff) regarding progress in implementing approved plans can provide early warning of adverse trends.

3.2 *Risk Management*

Given the new risks present in restructured markets, part of the reform equation is likely to involve issues related to risk management. What are best practices for risk management in a given utility? Certainly, the energy risk management system adopted for Idaho Power Company, a hydro utility, would not work for a fossil utility, or a distribution company that is procuring most of its supply. And once you’ve settled on a risk management strategy, how do you build it in to the consensus resource strategy? And recognizing that no risk strategy will perform perfectly, how do you avoid hindsight reviews? Idaho’s approach may be

instructive here; they have constructed risk tolerances which represent desired limits to the amount of risk they will bear. But they recognize that no strategy is full proof, so they have included early warning mechanisms to alert stakeholders if things are not working out. The cost of risk management may be another issue. Clearly, it costs something to be able to offer customers fixed rates in the face of changing market prices, and changing loads. The use of financial hedges entails premiums, or other counter party compensation, and the whole exercise of portfolio management takes highly skilled staff and computer resources. Obviously, these are legitimate costs of business, and need to be recovered in rates. Consumer advocates probably will concede this. But what they may not concede, and what economists will argue is essential for efficient risk management, is to give customers choices about the amount of risk management they want to pay for. Finally, there may be issues involving utility confidentiality. To the extent utilities define specific risk-management strategies (e.g., as part of a proposed resource strategy/plan), they may request that this information be treated in confidence, so that they can negotiate effectively in the market (i.e., to get the best deal for consumers).

3.3 *Least Cost Planning*

Regulatory reform may lead to a revival of “least-cost,” or integrated resource, planning. This is because LCP, a legacy of the late 1980’s and early 1990’s, still is practiced in many jurisdictions, and thus provides a convenient starting point for the development of new risk-management strategies and resource plans. And it is reasonable to expect that many of the same issues that have embroiled participants in traditional LCP, will be present in new resource policies and procedures.

For example, utilities may recognize that there can be diversity and environmental benefits in adding some renewable resources to a supply portfolio, but they also recognize that renewables tend to be more expensive than fossil alternatives; and they are sensitive to the potential for legislatures to mandate impractically high levels of renewables use, and for advocates to promote policies that subsidize renewable projects. The wisest course here may be to ensure that renewable resource development is market-driven (e.g., by giving customers “green” power

choices that avoid subsidies, but make customers aware that they are paying a premium for renewable power).

Distributed generation raises another whole set of issues (e.g., about how to value the system benefits of DG deployments; and how to design distribution rates so that DG owner/operators do not shift costs to other customers, or utility shareholders).

Demand-side management activities carry their own set of issues (e.g., involving how to identify cost-effective projects; how to fund DSM projects, whether in regulated rates, or through market-based transactions; and the potential to harm reliability if too much dependence is placed on DSM resources).

The basic issue for policy makers in the context of LCP may be how to achieve an appropriate balance in the “least-cost” resource mix, given the many objectives for resource planning, and the many constituencies, and agendas, involved.

3.4 Stakeholder Involvement

Given that reformed processes are likely to provide for the involvement of key stakeholder groups (staff, industrial representatives, residential and/or low-income consumer advocates, environmentalists, etc.) as a way to achieve buy-in and minimize subsequent rate case interventions, another issue in regulatory reform may be the need to ensure the integrity of the process in terms of being able to make decisions in a time frame needed to maintain a reliable system. Maybe this argues for the use of “hard” deadlines, with the commission able to step in and resolve impasses if need be.

4.0 Policy Principles

Considering the public interest in assuring new energy infrastructure investments for reliability and supply adequacy, and the relationship between investment risk and cost of capital, we propose the following principles to guide regulatory policies involving electricity resource planning and procurement:

- 1. Regulatory certainty is an essential pre-condition for needed new investment in energy infrastructure at reasonable cost.** The essence of regulatory certainty is regulatory support for the timely recovery of prudently incurred costs. Costs incurred in accordance with an approved resource plan should be presumed to be prudently incurred and eligible for recovery.
- 2. Consumer exposure to volatile wholesale markets can be minimized through risk management.** Resource plans should identify key risk exposures, and should define explicit strategies and guidelines for managing such risks. Where risk management strategies and guidelines are approved and prudently implemented, regulatory authorities should provide cost recovery. Risk management strategies should be subject to confidentiality requirements.
- 3. Guidelines for meeting resource requirements should reflect market conditions and balance state, regional, and consumer needs.** Resource planning and procurement guidelines should balance relevant objectives, including reliability, credit risk by market participants, cost minimization, environmental quality, and cost/price stability.
- 4. Stakeholders should be engaged in the review of plans to meet resource requirements, including new infrastructure investments, needed to ensure electricity supply adequacy.** Including stakeholders in the review of plans will lower risks and consequently lower rates for consumers.
- 5. The reasonableness of utility decisions must be judged on the basis of facts known at the time that the decision was made, not on the basis of “perfect hindsight.”** The reasonableness of actions taken to implement commission-approved resource plans should be based on the prudent judgment of the utility in following defined resource guidelines, not on the ultimate outcome of such actions.

- 6. Resource planning and procurement policies should be guided by the need to provide adequate, reliable, and economically efficient supply services to consumers.** Risk management, both regulatory risk and resource risk, is appropriate because it will benefit consumers.

Appendix A: Recent Regulatory Precedents

State: AR
Reference: Docket No. 01-023-NOI, Order No. 3; 210 PUR 4 th pages 325-330
Date: 6/20/01
Scope: Principles to guide gas hedging
<p>Abstract: The Arkansas Public Service Commission promulgates eight principles to guide hedging by jurisdictional gas utilities, as follow:</p> <ol style="list-style-type: none"> 1. Each gas utility is expected to take all reasonable and prudent steps necessary to develop a <i>diversified</i> gas supply <i>portfolio</i>. The portfolio should consist of an appropriate combination of different types of gas purchase contracts and/or financial hedging instruments that is designed to yield the optimum balance of reliability, reduced volatility and reasonable price. In so doing, each utility should take into consideration various factors including, but not limited to, its particular circumstances, the demographics of its customers, the then-current market projections of both volatility and price, supply/demand estimates, and other relevant information that is available in the industry. (Emphasis added) 2. On an <i>annual</i> basis, each utility should submit its <i>gas supply portfolio plan</i>, along with its contracting and/or hedging objectives, to the General Staff for Staff/s review and determination as to whether or not it appears to be consistent with these policy principles. The <i>reasonableness and prudence</i> of each utility’s contracting and hedging decisions <i>shall be judged</i> by the market circumstances and pertinent information that was available to the utility at the time it made those decisions. (Emphasis added) 3. Each gas utility should <i>submit proposed revisions to its PGA or GSR</i>, as appropriate, to reflect the flowthrough of any costs associated with hedging transactions. (Emphasis added) 4. To the extent that there are fee-based <i>costs associated with a particular financial risk management instrument</i>, as those costs relate to the acquisition of natural gas supplies, such costs <i>may be recovered through the utility’s Purchased Gas Adjustment Clause (PGA)</i>. (Emphasis added) 5. Each gas utility should <i>maintain records</i> for any hedging programs it chooses to utilize that document the following: (Emphasis added) <ol style="list-style-type: none"> A. The overall risk management plan, including the utility-specific goals and guidelines. B. A Policy and Procedures Manual.

AR - Docket No. 01-023-NOI, Order No. 3; 210 PUR 4th pages 325-330 - CON'T

C. Corporate (including management and Board of Directors) reporting, monitoring, and tracking requirements.

D. An evaluation mechanism to *measure hedging program performance*. (Emphasis added)

E. Accounting information to determine: (1) the fees, gains, and losses that have flowed through the PGA, and (2) the FAS and IRS *accounting treatment for hedging transactions*. (Emphasis added)

6. Each gas utility should engage in appropriate *customer education* efforts to inform as many of its customers as practical concerning the utility's good-faith estimate of gas prices for each upcoming winter heating season.

7. *Levelized billing* or average payment plans should be made available to all residential and small business customers.

Implementation of this principle should include sufficient customer education efforts to encourage maximum customer participation with particular attention to low income, fixed income, and elderly customers. Any gas utility needing assistance with efforts to identify, educate and inform low income, fixed income, and elderly customers should contact the Commission for help and suggestions for designing an education plan designed to reach these customer groups. (Emphasis added)

8. The Commission encourages each gas utility to explore and, if appropriate, develop and implement fixed-commodity gas supply options for its customers.

State: CA
Reference: Assembly Bill No. 57, see: http://www.leginfo.ca.gov/pub/01-02/bill/asm/ab_0051-0100/ab_57_bill_20020924_chaptered.pdf
Date: 9/24/2002 (signed into law)
Scope: Statutory authority for up-front approval of standards and criteria for (prudent) resource procurement
<p>Abstract: The California legislature provides guidance to the California Public Utilities Commission about how to provide regulatory certainty, sufficient for utilities in the state to become credit worthy and resume buying resources to serve their customers. The legislature’s essential strategy is to require the PUC to review and approve utility procurement plans that define acceptance criteria for subsequent utility procurement contracts. Once the PUC approves plans, contracts that meet the criteria are to be approved, and associated costs recovered timely in rates, <i>without reasonableness review</i>. The PUC is allowed to review contract administration (e.g., to ensure that that contracts are administered in accordance with their stated terms and conditions), and contract disputes which may arise. It also can engage independent consultants to evaluate a utility’s risk management and strategy.</p> <p>The statute directs the PUC to specify the allocation to each utility of power procured by the state Department of Water Resources (DWR), then requires utilities to file proposed procurement plans within 60 days thereafter. Plans must address the following:</p> <p>Price Risk – An assessment of the price risk presented by the utility’s resource portfolio. (Note - Utilities are required to maintain diversified portfolios of long and short-term procurements, demand-reduction “products,” and “electricity-related products;” presumably, financial hedges.)</p> <p>Resources To Be Procured – Definitions, and related justifications, for the products to be procured, including financial instruments.</p> <p>Duration – The duration of the plan, including the duration, timing, and range of products to be procured.</p> <p>RFP Process – The competitive process by which the utility will procure resources.</p> <p>PBR - A description of any incentive mechanism the utility wishes to propose for treatment of procurement costs.</p> <p>Acceptance Criteria – The upfront standards and criteria by which the acceptability and eligibility for rate recovery of procurements will be judged. (Note - The intent is for utilities to be able to accurately predict whether costs will be considered reasonable or not.) This element of each plan is supposed to include an expedited approval process for contracts executed pursuant to the plan.</p> <p>Procedures For Updating – A procedure for updating the procurement plan.</p> <p>Renewables – The plan must show that it will increase the renewable resources component of the portfolio by 1%/year until renewable resources constitute 20% of the portfolio. This requirement is subject to the condition that “...sufficient funds are made available...to cover the above-market costs for new renewable energy resources.”</p> <p>Risk Management Strategy – The utility’s risk management strategy, including specific measures of price stability. (Note - The PUC is directed to ensure the confidentiality of any market sensitive information, provided that the Office of Ratepayer Advocates and</p>

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other consumer groups are provided access to such information.)

To ensure timely recovery of costs, the PUC is directed to base rates on forecasts of procurement costs, actual costs, or a combination thereof; and to establish balancing accounts to track costs, and to review such accounts not less than semiannually. Through January 1, 2006, the PUC must ensure that overcollections or undercollections do not exceed 5% of the utility's generation revenues for the prior year, excluding revenues collected for the DWR. After 1/1/2006 balancing account adjustments are to be made when the PUC deems appropriate.

The extent of CA's retreat from market-based restructuring is reflected in SEC. 2. (j) (2) of this statute, which provides that: "Any electrical corporation's procurement necessitated as a result of the divestiture of generation assets on or after the effective date of the act adding this subdivision shall be subject to the mechanisms and procedures set forth in this section only if its actual costs is less than the recent historical cost of the divested generation assets." (Emphasis added) Note also SEC. 3, which states: "Nothing in this act is intended to imply that procurement of electricity from third parties in a wholesale transaction is the preferred method of fulfilling an electrical corporation's obligation to serve its customers at just and reasonable rates."

The California Public Utilities Commission implemented AB 57 in an order dated October 24, 2002. (See CPUC Decision 02-10-062, Rulemaking 01-10-024; 220 PUR 4th at 377).

State: CA
Reference: Rulemaking 01-10-024, Decision 02-08-071
Date: August 22, 2002 (confirm)
Scope: Securing up-front prudence approval
<p>Abstract: The CA Public Utilities Commission adopts a process to give CA IOUs up-front reasonableness approval for electric procurement contracts. The process will be used through January 1, 2003, after which a permanent process (currently being developed) is expected to be implemented. The interim process is composed of seven major steps, as follows:</p> <ol style="list-style-type: none"> 1. Planning - The utility works with a Procurement Review Group (i.e., PUC Energy Division staff, Office of Ratepayer Advocates staff, other parties who are “not market participants”) to develop a plan for stabilizing and minimizing retail rates during the transitional period. If the plan requires incremental resource procurements, the utility works with the Group to publish a request for proposals and evaluate bids received. 2. Application - The utility submits winning bids to the PUC, along with descriptive information defined in a Master Data Request (e.g., a description of the process used to obtain the bid, a description of the quantitative process used to rank bids, a copy of the software used to evaluate bids, an electronic copy of any data or forecasts used to analyze bids). 3. Protests - Any protests to the proposed contracts would be addressed via the filing of formal protests at the PUC, and formal replies to protests, presumably filed by the utility. 4. Workshop - A workshop is held to discuss the application. 5. ALJ decision - An Administrative Law Judge, in consultation with an assigned Commissioner, issues a ruling indicating whether the ALJ intends to prepare a draft Commission decision (i.e., because the Application is uncontested), or whether there are controversial issues requiring a hearing. 6. Hearings - If needed, hearings are held on the application, giving opponents an opportunity to register their concerns. 7. PUC Vote - If the ALJ drafts a decision for the PUC, it is placed on its next agenda and voted on. Approval of the proposed decision “...shall be dispositive of all prudence questions which might arise at a later date regarding the contracts, absent a showing of: (a) misrepresentation or omission of material facts of which the utility is aware in connection with the utility’s request for contract approval; and (b) imprudence in the utility’s performance under the negotiated contract.” <p>The timeframe for a decision approving contracts as prudent, assuming there are no issues of substantial controversy, is intended to be about 60 days from the filing of the Application - plus whatever time is required for the ALJ to publish a decision and prepare a draft PUC decision. If the ALJ certifies that there are issues of substantial controversy, the timeframe is increased by 30 days or more, depending on whether hearings are held.</p>

State: CA
Reference: Decision 02-08-064, Investigation 01-06-047; 219 PUR 4 th at 421
Date: 8/22/02
Scope: Failing to hedge was imprudent
<p>Abstract: The California Public Utilities Commission finds that Southwest Gas Company was imprudent in not hedging its gas supply costs for the winter of 2000-2001 and disallows \$2.691 million in gas acquisition costs.</p> <p>The Commission established that the Company had made use of gas storage in preceding years (i.e., 1.4 Bcf – 93% of its contracted storage capacity in 1999, 1.4 Bcf – 93% of capacity in 1998, 1.1 Bcf – 73% of capacity in 1997, .75 Bcf – 50% of capacity in 1996), but stored only .17 Bcf during the summer of 2000. Neither did the Company use financial derivatives to hedge (stabilize) its supply cost during the winter of 2000-2001. As a result, the Company’s supply costs escalated dramatically. During the three years ended December 2000, the Company’s gas supply cost \$2.21 per Dth. On December 1, 2000 the Company’s supply cost jumped to \$8.62 per Dth; in January its cost escalated to \$12.96 per Dth; in February and March costs escalated to \$15.76 per Dth.</p> <p>Against this background, the PUC finds the Company imprudent for not having filled at least 50% of its storage; or, alternatively, securing contracts for future delivery of an equivalent amount of gas.</p> <p>Commenting on the applicable standards of reasonableness, the Commission said “We have first examined the goals that the utility hoped to achieve in the negotiations and have evaluated whether that goal was reasonable. We then compared the actual outcome with the goal. Finally, we considered whether a reasonable and prudent utility would have taken other steps to come closer to achieving the utility’s goal ... Thus, although the utility need not show that it has undertaken the optimal act, it must show that its course of action was reasonable and that the utility took care in making its decision.”</p>

State: CO
Reference: Docket No. 02R-137E, Decision No. C02-793; 219 PUR 4 th 201
Date: 5/29/02
Scope: Up-front prudence review of a “least cost” plan
<p>Abstract: The Colorado Public Utilities Commission adopts new least cost planning rules which provide for up-front prudence review, rather than after-the-fact review.</p> <p>Under the new rules, jurisdictional utilities are required to file least-cost resource plans every four years. (They can file interim plans more frequently, if needed.) The Commission reviews each plan, and issues a written decision approving, disapproving, or ordering modifications to it. If the record contains sufficient evidence, the Commission’s decision specifically approves or modifies (1) incremental resource needs, (2) the plan for acquiring incremental needs, and (3) components of a proposed RFP. (If the Commission declines to approve a plan, in whole or in part, the utility must file an amended plan within 60 days.)</p> <p>According to the Commission, “A Commission decision specifically approving the components of a utility’s plan creates a presumption that utility actions consistent with that approval are prudent. Because the Commission will not approve a utility’s selection of specific resources, the Commission’s approval of a plan creates no presumptions regarding those resources.” In order to recover new resource costs in rates, a utility must present <i>prima facie</i> evidence that it acted in accordance with its approved plan. Intervenors seeking to oppose cost recovery must present evidence to overcome the utility’s <i>prima facie</i> evidence, or to demonstrate that “...due to changed circumstance timely known to the utility or that should have been known to a prudent person, the utility’s actions were improper.”</p> <p>Least cost plans must contain, among other things, an assessment of additional resources needed, and Request for Proposals (RFP) the utility proposes to use to solicit such additional resources. Included with proposed RFPs must be a written bidding policy that ensures fair and reasonable evaluation of bids. The utility itself, or its affiliate, may bid; but in this event, the utility must submit a separation policy, and must hire an independent auditor to review and report on the fairness of the bid evaluation process. The utility must also identify and support proposed planning reserve margins, by year, at base, low, and high demand scenarios. Plans should minimize the net present value of revenue requirements, but also consider “...renewable resources, resources that produce minimal emissions or minimal environmental impact; energy-efficient technologies; and resource that provide beneficial contributions to Colorado’s energy security, economic prosperity,</p>

CO - Docket No. 02R-137E, Decision No. C02-793 – Con’t

environmental protection, and insulation from fuel price increases...”

Although the rules require that incremental resource needs generally be acquired through competitive bid, utilities can use an “alternative method of resource acquisition” if they can justify it. Certain resources are exempted by rule from competitive procurement, including emergency maintenance or repairs, generators below 30 MW, and purchase contracts of not more than two years’ duration. There are limits on how much resource can be acquired through alternative methods.

State: IA
Reference: An Act Relating To Electric Power Generation and Transmission, Sec. 476.53, House File 577
Date: 7/3/01
Scope: Statutory authority to provide binding up-front determinations of rate treatment for new energy facilities
<p>Abstract: Iowa amends its public utility code to authorize/require the PUC to provide binding up-front commitments regarding the ratemaking treatment to be accorded new projects by utilities in the state. Noting that “It is the intent of the general assembly to attract the development of electric power generation and transmission facilities within the state in sufficient quantity to ensure reliable electric service to Iowa consumers and provide economic benefits to the state,” the Act directs the Utilities Board to issue orders defining, for projects that qualify, the “rate making principles” that will be applied to generation and transmission facilities built or leased in the state - and to do so <u>before</u> projects are initiated.</p> <p>In order for a project to qualify, the Commission must find (1) that it will be owned by a rate-regulated public utility; (2) that the facility will have a generating capacity of at least 300 MW; (3) that the facility will be a base load facility, a combined-cycle facility, or an “alternative energy production facility” (i.e., wind, methane, agricultural crops or residues, or small hydro); (4) that the facility will be owned, or leased, in Iowa; (5) that the utility has in place a Board-approved energy efficiency plan; and (6) that the utility has considered other long-term supply sources, and that the proposed facility “...is reasonable when compared to other feasible alternative sources of supply.” The Act does not apply to purchased power contracts. Utilities can satisfy requirement # 6 through a competitive bidding process, or in some other way.</p> <p>For facilities that qualify, the Board is directed to determine applicable rate making principles through a contested proceeding, and then publish an order setting forth these principles. The order “...shall be binding with regard to the specific electric power generating facility in any subsequent rate proceeding,” and if the utility does not like the rate treatment, it can withdraw its application.</p> <p>This authority was first exercised in a decision establishing the rate treatment to be accorded a combined-cycle facility proposed by MidAmerican Energy Company. Pursuant to a contested proceeding, the Board issued an order committing to the following rate parameters: use of the same capital structure ratios and costs (except for the cost of common equity) as are used for the utility’s other electric operations; include the unit’s capital and operating costs in Iowa rates, use the same methodology to allocate capital and operating costs as is used for the utility’s other generating facilities; use a depreciable life of 27.6 years for ratemaking purposes; exclude the proposed facility from any future calculation of excess capacity, or related penalty; provide that corresponding load adjustment based upon a 20 percent normal weather reserve margin is made; establish a “soft” cap of \$357.49 million, exclusive of</p>

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AFUDC, for the facility; and set allowed return on common equity at 12.23 percent. (Reference: Iowa Utilities Board, Docket No. RP-U-01-9, issued 5/29/02; http://www.state.ia.us/government/com/util/_private/Orders/2002/0529_rpu019.pdf.)

This authority was exercised for a second time when the Board approved a settlement defining the rate making treatment to be accorded the Power Iowa Energy Center (PIEC), a 632.4 MW combined cycle generating station proposed by Interstate Power & Light Company. The settlement provides for a return on common equity of 12.23%, a depreciable life of 27.6 years, and the recovery of cancellation costs if the project is cancelled for good cause. However, this settlement includes a rate making principle relating to traditional regulatory review, which sets it apart from the earlier MidAmerican project. This fourth principle provides that certain capital and operating costs will be deferred in a regulatory asset account until the costs are included in rates, provided “...*that the prudence of the costs may be disputed by any party and shall be subject to determination by the Board.*” (emphasis added) (Ref. Iowa Utilities Board, Docket No. RPU-02-6, issued 9/17/02; 220 PUR 4th at 273)

State: ID
Reference: Case No. IPC-E-01-16 (Phase II), Order No. 29102; 220 PUR 4 th page 193
Date: 8/28/02
Scope: Adopting a unique risk management program for a hydro utility
<p>Abstract: The Idaho Public Utilities Commission adopts a settlement agreement that structures risk management practices at Idaho Power Company. (The Company’s purchased power costs escalated rapidly during 2000 and 2001, culminating in applications in February and March 2001 for approval to recover these costs in its Power Cost Adjustment - PCA - mechanism. In Order No. 28722 the Commission approved the recovery of \$168.3 million, but deferred recovery of a further \$59 million pending further investigation of the Company’s hedging and risk management practices. This agreement is an outcome of that investigation.)</p> <p>Every year the Company will conduct one or more collaborative workshops with staff and customer representatives to review the resource-related risks facing the Company and its customers. The Company will solicit input from staff concerning appropriate risk tolerances for the coming year. The Company will then establish Risk Guidelines that define maximum amounts of risk the Company will accept from any of three sources (i.e., Tier 1 – from changes in the Company’s load and wholesale market prices, Tier 2 –from changes in hydro availability, Tier 3 –from wholesale prices declining below levels at which the Company has agreed to buy power). As the Company manages to the foregoing tolerances, it will notify the Commission and staff, in confidence, when it enters into forward monthly contracts whose price exceeds a pre-defined Market Review Trigger. This is to provide early consumer price signals (i.e., by adjusting retail rates) in a rising market. The Company also agrees to organize an internal Risk Management Committee (RMC) that is separate from IDACORP, its corporate parent; and to document decisions of the RMC for possible audit by Commission staff.</p> <p>During the first year of the agreement, the Tier 1 limit is set at \$100 million, meaning the Company will apply hedges, as needed, to try to keep increases in the PCA balance at or below \$100 million. The Tier 2 limit is set at +/- 100 MW, meaning that the Company will enter into forward contracts to sell (surplus months), or buy, (deficit months) as needed, to keep its “open” position (i.e., the amount of power that is not under contract) at or below 100 MW. The Tier 3 limit is set at \$30/MW high load, and \$15 MW/low load, meaning that the Company will seek to cover deficiencies whenever prices fall below \$30/MW during heavy load, and \$15/MW during light load conditions. The Company also will try to buy power to cover low water deficiencies whenever prices fall below \$20/MW (heavy load) and \$10/MW (light load). For all three tiers, hedges will be entered into in units, or tranches, of 25MW, and removed in tranches of 50 MW. The Market Review Trigger is set at \$60/MW.</p> <p>The agreement recognizes that uncontrollable violations of the Tier 1 risk limits can occur, and provides that should this happen, the Company will expeditiously advise the Commission, staff, and a Customer Advisory Group of the violation, and of actions the Company is taking to contain the violation.</p>

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(Note: In an October, 2002 presentation to EEI’s Economic Regulation and Competition Committee, Idaho Power Company emphasized that managing regulatory risk effectively involves much more than just using financial derivatives; it involves facilitating regulatory and customer buy-in to risk management decisions, and involves the ongoing provision of information and education to stakeholders via documentation and reporting practices.)

State: KS
Reference: Docket No. 98-KGSG-475-CON; 215 PUR 4 th pages 572-576
Date: 2/14/02
Scope: Securing up-front prudence approval for gas hedging
<p>Abstract: The Kansas State Corporation Commission approves a settlement agreement modifying the gas hedging program of Kansas Gas Service Company for the 2002-2003 heating season. The Agreement, negotiated among the Company, Staff, and the Citizens' Utility Ratepayer Board (CURB), provides for: (1) a \$7.3 million budget for the Gas Hedge program during the 2002-2003 heating season, and (2) a risk management strategy (the details of which are classified as confidential commercial information), but which Staff affirms as "...consistent with the public's preferred risk management strategy. A sampling of the public revealed a preference for protection against high prices while retaining downside risk." (3) implementation of the strategy as soon as possible, (4) issuance by the Company of an RFP for the management and use of the Company's storage and transportation facilities during the summer injection period, (5) that Gas Hedge program costs will be recovered in rates during the months April through October 2002 without carrying charges, (6) that the Company will file a monthly report detailing the status of the program. The Company also undertakes to meet with Staff and CURB each month, or as otherwise requested, to discuss the program, (7) that CURB can advocate for other hedging strategies at other times, under other market conditions. In addition to the provisions of the Agreement, the Company had asked the Commission to issue an accounting order authorizing the Company to "...record in an account those monies expended by Kansas Gas Service in establishing price volatility protection for the 2002-2003 heating season (and) recover the balance of such account in equal amounts through the Company COGR (adjustment mechanism)..."</p>

State: KY
Reference: Case No. 2001-00128, 219 PUR 4 th at 354
Date: 6/7/2002
Scope: Authorizing an LDC to continue a pilot gas hedging program
<p>Abstract: The Kentucky Public Utilities Commission authorizes the Union Light, Heat and Power Company to continue a pilot gas hedging program through the 2002-2003 heating season. The Company requested two modifications from the first year of the program; namely, elimination of the use of price cap instruments, and a reduction in the volumes of gas to be hedged. There was no indication in the Commission's order as to why the Company did not wish to continue using price caps. (Price caps are contracts which establish a maximum price for a specified volume of gas over a specified time period. Below the cap prices are based on a market price index plus an adder, or premium, to compensate the counterpart for the capped price obligation)</p> <p>In approving the requested extension, the Commission took note of an argument by the state's Attorney General that the Company had conducted no research to ascertain customer preferences for price stability vs. price minimization. The Company was ordered to work with staff to survey customers on this question.</p> <p>The Company also was ordered to develop written policies and procedures for conducting hedging activities within 60 days.</p>

State: LA
Reference: Docket No. R-26172, 217 PUR 4 th , pages 201-209
Date: 4/10/02
Scope: Securing up-front prudence approval
<p>Abstract: The LA Public Service Commission adopts a planning process designed to restore regulatory certainty to support the construction of new generation in the state. (In December 2001 the commission had issued an order declining to proceed with retail access, and during the preceding three years utilities in the state had sought to fill new capacity needs through short to intermediate purchases rather than through new construction.) Under the new planning and approval process, utilities demonstrate the reasonableness of new projects by testing them against the market via an RFP process (i.e., to see whether third parties can beat the utilities' cost and/or schedule). The Commission describes the new process as "...one of technical review and consultation ...rather than litigation." In Phase-I a utility seeking a certificate of public convenience and necessity (CCN) to build or acquire capacity files information describing (1) the identified capacity need (and supporting analysis; e.g., load projections) , (2) the cost of a self-build proposal (the utility can request that self-build cost data be treated in confidence) , (3) a draft RFP for purchasing power or building a plant, (4) a proposed schedule, and (5) a description of how proposals will be evaluated. Staff and other participants review the filing; the utility conducts one or more technical conferences, as needed, for this purpose. The utility issues the RFP, and evaluates the bids received. Again, staff and other qualifying participants can review and provide input into the utility's evaluation process. In Phase-II the utility applies formally for a CCN, using the results of Phase-I to support its application. An exemption to this process is provided for resources less than 35 MW and contracts for emergency or economy power.</p>

State: MA
Reference: D.T.E 00-66, 00-67, 00-70; 206 PUR 4 th pages 122-133
Date: 12/4/2000
Scope: Recovering fuel cost increases despite a mandated rate reduction
Abstract: The MA Department of Telecommunications and Energy authorizes jurisdictional utilities to flow through increased fuel costs incurred in purchasing power to serve standard offer service customers (i.e., via a fuel adjustment mechanism), rather than defer such costs for future recovery. The Department rejected recommendations of the MA Attorney General and other low-income advocates to delay implementation of the standard offers service fuel adjustment mechanism, on the basis that such implementation would conflict with the Electric Industry Restructuring Act. That Act requires that standard offer service customers receive a 15% reduction from rates in effect in August 1997. The Department ruled that fuel cost recovery should not be constrained by the Act because (1) deferred costs would be recovered from all customers, including those who left standard offer service; (2) costs deferral could threaten the solvency of MA utilities, which would threaten the safety and reliability of distribution services; and (3) pricing standard offer service below cost would impeded the development of a robust competitive electricity market.

State: MT
Reference: Working Draft (provided by Northwestern Energy)
Date: 9/27/2002
Scope: Resource planning and procurement guidelines
<p>Abstract: Northwestern Energy (formerly Montana Power Company) has been working with the Commission Staff and other Stakeholders to develop a set of guidelines for planning and procuring resources to meet Default Supply Service (DSS) obligations. These draft Guidelines do not define a specific planning and approval process, but focus criteria the Commission will use in evaluating the reasonableness of Company activities related to (1) default supply resource planning and procurement, (2) affiliate transactions, and (3) documentation.</p> <p>Regarding planning, the Guidelines are premised on the use of portfolio management, and indicate that the Company should clearly define the resources it needs; should consider the risk-related attributes of resource alternatives (e.g., scheduling flexibility, lead-time, match with load growth, scenario testing to develop robust resource strategies); should consider demand-side resources on an equivalent basis to supply-side resources; should establish bid evaluation and bidder qualification criteria up-front; should procure resource needs through competitive bid; should conduct due diligence regarding the qualifications of bidders on a short list; should give all bidders an opportunity to submit updated bids if new evaluation criteria are added; should treat bids in confidence until contracts have been signed; should work with a Technical Advisory Committee (TAC), composed of non-Company stakeholders, to provide technical advice on the Company's default supply resource planning and procurement process; and should produce default supply energy portfolios that can be understood by the public and the Commission.</p> <p>Regarding affiliate transactions, the Guidelines indicate that the Company should have an independent third party review contracts involving affiliates before they are executed, and should consult with the TAC in choosing an independent third party; should not provide to affiliates any information regarding competitive procurements which is not provided simultaneously to all other prospective bidders; should ensure that the utility has not compromised its default supply duties and obligations in favor of an affiliate corporate entity; should observe the "no harm to ratepayer" cost standard (i.e., purchases from affiliates at the lesser of cost or market); should separate costs and revenues between the utility and the affiliate; should ensure that the Commission has access to the books and records of the affiliate for audit purposes; should report affiliate transactions and relationships to the Commission annually; and should establish an "adequate" code of conduct to provide day-to-day guidance to management and other employees.</p> <p>Regarding documentation, the Guidelines anticipate annual cost recovery filings, and indicate that such filings should be supported by documents demonstrating due diligence regarding the qualification of bidders; describing the resource attributes considered in evaluating resource alternatives; reflecting how resource attributes were weighted; describing any ranking methodology and selection criteria used; reflecting computer modeling and analysis used in selecting bids; describing management judgments made in selecting</p>

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bids for contract negotiation; and describing related input received from the Technical Advisory Committee. To the extent the utility does not use competitive solicitations, it should thoroughly document the exercise of its judgment in resource selection and its rationale for not using competitive bids.

Note that the Company is obligated to conduct planning and procurement to serve two categories of DSS; namely, Short-Term Service (service which the customer takes for a year at a time) and Long-Term Service (service which the customer is assumed to take indefinitely). The Company is not required to plan, procure, and maintain reserves to provide Emergency Service.

Note also that the Guidelines provide for “opportunity resources” (i.e., resources which are available on short notice, whose use will lower supply costs) without following the normal RFP process. The Guidelines acknowledge that Northwestern Energy should procure such resources when they will provide economic benefit and are consistent with the Guidelines, but should thoroughly document and justify such procurements.

State: NC
Reference: Docket No. G-100, Sub 84; 215 PUR 4 th pages, 349-360
Date: 2/26/02
Scope: Encouraging gas LDCs to hedge fuel costs
<p>Abstract: The NC Utilities Commission orders jurisdictional gas utilities to describe their hedging policies and practices during annual gas prudency reviews; or, in the alternative, to explain why they decided not to hedge. (Note: this docket was opened after the Commission held two informal meetings to assess what could be done to limit the volatility of consumer gas prices experienced during the winter of 2000-2001. Apparently, the Commission learned that hedging tools are available, but that LDCs have not used them for fear that they would be exposed to large regulatory prudence risks. At the conclusion of the information meetings, the Public Staff recommended a formal, docketed proceeding to examine prudence issues in greater detail. This Order is the product of that formal proceeding.) In the Order the Commission affirms: (1) that there is no one hedging strategy suitable for all LDCs in the state, each utility must decide whether, and how, to implement hedging; (2) that if an LDC uses hedges, the premiums or other transaction costs incurred are appropriately recovered through the state’s purchased gas adjustment (PGA) mechanism; (3) that the Commission is constrained by law from providing up-front prudence approval of hedging contracts, and that such approval must be obtained as part of an annual review of gas cost reasonableness and prudence; and (4) that prudence reviews should be conducted on the basis of the information available at the time each decision was made. In explaining this last point the Commission said: “While the Commission cannot accept pre-approval, it acknowledges the UDCs’ concern over the fairness of hindsight reviews. Several parties commented that the prudence of hedging decisions should be judged based on facts know at the time the hedging decision was made... The Commission emphatically agrees with these comments. The review of the prudency of hedging decisions, including both any hedging plan and any decisions made during the implementation of such a plan, should be conducted on the basis of facts known at the time the decision to hedge (or not to hedge) was made and not on the basis of the outcome of the hedging decisions.”</p> <p>Regarding # 2, above, the Commission did qualify that pursuant to Commission Rule R1-17(k)(2)(b), recovery of hedging costs through the PGA might not be possible in situations where the counter party does not meet the definition of a “Supplier.” The Commission asked for comment on what amendments to Rule R1-17(k)(2)(b) might be needed to obviate this problem.</p>

State: NJ
Reference: Docket Nos. GR99100778, et al., 216 PUR4th pages 444-449
Date: 3/7/02
Scope: Deciding not to hedge gas procurements was reasonable, based on what was known at the time
<p>Abstract: The NJ Board of Public Utilities rejects a motion by the NJ Division of Ratepayer Advocate to reconsider orders issued on March 30, 2001 that allowed nearly full recovery of gas procurement costs incurred by NJ utilities during the period April 1, 2001 to October 31, 2001. The Advocate had urged a disallowance on the grounds that three of the four NJ utilities had not implemented hedging strategies. The BPU finds that it was not imprudent for the LDCs not to have hedged, explaining “Although the Advocate argues that the purpose of hedging is to guard against just such unexpected price increases, the completely unprecedented sharp risk in gas prices through the year 2000 plainly justified some hesitation to lock in the high prices encountered in the summer and fall of 2000... Given this fact (that gas procurement is complex) and the extraordinary circumstances existing at the time the companies’ procurement decisions were made, the Board cannot, on hindsight, find those decisions to have been unreasonable.” Nevertheless, the Board did agree with the Advocate that new gas procurement guidelines are needed to deal with volatile wholesale markets, and did confirm that it has directed gas utilities in the state to submit hedging programs for review by the Board.</p>

State: NV
Reference: Docket No. 01-11029; 216 PUR4th, pages 557-613
Date: 3/29/02
Scope: Finding purchased power costs were incurred imprudently
Abstract: Nevada Public Utilities Commission disallows \$437 million in deferred purchased fuel and power costs incurred by Nevada Power Company between 3/1/01 and 9/30/01 on the basis that the Company was imprudent in: (1) failing to execute a contract with Merrill Lynch in 1999 to buy power at a cost between \$32.75 to \$39.25 per MWh at a time the company's average cost of purchased power was \$40.86/MWh, (2) purchasing excessive amounts of on-peak power (i.e., in excess of 107% of its monthly average peak load, (3) purchasing excessive amounts of off-peak power, and (4) engaging "...in at least some speculation that it could benefit from power sales" (e.g., by selling back in to the California market).

State: OK
Reference: Cause No. PUD 200100097, Order No. 454611; 211 PUR 4 th pages 230-243
Date: 7/25/01
Scope: Principles to guide gas hedging
<p>Abstract: Pursuant to a motion by staff, the Commission issues this Order setting forth eight policy guidelines for review of gas LDCs' strategies, as follow: (The Commission finds that)</p> <ol style="list-style-type: none"> 1. ...ONG (Oklahoma Natural Gas Co.) should take such steps as are reasonable and prudent to develop an appropriate diversified gas supply portfolio plan and risk management plan, which is in the best interests of its ratepayers. 2. ...ONG shall periodically update and annual file its gas supply portfolio plan and risk management plan with the Staff, no later than May 15th of each year. The reasonableness and prudence of ONG's contracting and hedging decisions shall be reviewed pursuant to the Commission's Gas Rule. PAC 165:45 and OAC 165:50, applicable statutory and constitutional provisions of Oklahoma law. 3. ...ONG may submit proposed revisions to its PGA or GAR, as appropriate, to reflect the utility's request to flow-through cost or gains associated with financial hedging transactions. The Commission makes no determination regarding prudence or reasonableness of the flowthrough of costs in this Order. 4. ...ONG shall maintain complete records for any hedging programs it elects to utilize. 5. ...ONG should engage engage in appropriate customer education efforts to inform as many of its customers as practical regarding prices for the upcoming winter heating season, including information related to levelized billing or average payment plans or other customer programs. Accordingly, Oklahoma Natural shall submit the customer notification to the Commission for approval by the Director of the Public Utility Division and the Director of the Consumer Services Division, at least fifteen (15) days prior to notification of customers. ONG shall notify its customers of the availability of the optional pilot program sixty (60) days prior to implementation of the program. 6. ...ONG shall continue to keep the Staff closely informed of procurement options available and decisions it makes to mitigate the volatility of energy prices to its ratepayers, and shall continue to participate in collaborative discussions regarding appropriate documentation to be provided to the Commission.

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7. ...ONG should be encouraged to seriously consider all the various energy supply procurement practices available to it and to carefully weigh the potential costs and benefits of each before utilizing a particular practice.

8. ...for the purpose of allowing further inquiry regarding the hedging plans of gas utilities in Oklahoma, further investigation of the appropriateness of financial hedging to mitigate gas price volatility should be undertaken through a Notice of Inquiry... and approving a Voluntary Fix-Price pilot program.

State: OR
Reference: Docket UE 115, Order No. 01-777
Date: 8/31/01
Scope: Purchased power cost incentive mechanism
<p>Abstract: The Oregon Public Utility Commission approves new rate schedules for Portland General Electric Company that reflect the increased cost of wholesale power, and the functional unbundling requirements of Oregon Senate Bill 1149. Included is a Power Cost Adjustment mechanism which tracks variances in power cost (actual vs baseline) and shares overages or savings between customers and the Company, based on a pre-defined sharing formula. Power Cost Variance is defined as the difference between actual and base net variable power costs, less the difference between actual and base energy revenues for the period October 2001 through December 2002. Variances are calculated on a quarterly basis; the first +/- \$28 million falls within a deadband (i.e., the Company absorbs all the overage or retains all the savings), amounts over \$28 million are shared with customers in increasing proportions (i.e., from 50% for variances from \$28 - \$38 million, to 95% of variances over \$200 million).</p>

State: VA
Reference: Case No. PUE010354; 212 PUR 4 th pages 375-378
Date: 9/28/01
Scope: Recovering the cost of gas hedges through fuel adjustment mechanisms
<p>Abstract: The Virginia State Corporation Commission approves the recovery of hedging costs through the fuel adjustment mechanisms (Purchased Gas Charge) used by Washington Gas Light Co. and The Shenandoah Gas Division of Washington Gas Light Co. These companies are authorized to use three kinds of hedging instruments through the 2005-2006 heating season (i.e., <i>price caps</i>, defined as contracts which establish a maximum price for a specified volume of gas over a specified time period. Below the cap prices are based on a market price index plus an adder, or premium, to compensate the counterpart for the capped price obligation; <i>price bands</i>, defined as contracts which require the utility to pay a market index price up to a maximum cap price and down to a minimum floor price. The counter party receives compensation through the utility's obligation to the floor price; and <i>fixed price hedges</i>, defined as contracts that establishes a price for a specific volume of gas over a specific period. Compensation to the counter party is embedded in the positive difference between the contract price and the current price of gas.) The companies are directed to file an annual report on or before June 30 describing the terms of the hedging instruments used in the prior heating season, costs incurred to provide counter party compensation, and the calculation of maximum daily take volumes that will be used to guide the negotiation of hedges for the next heating season. By June 30 of the 2005 heating season, the companies must indicate whether they wish to continue using hedging instruments, and if so, how they may wish to change such use. Through 2005, if the companies want to change their hedging programs (i.e., either the portion of their supply portfolio which is hedged, or the methods for hedging), they must apply to the Commission for approval to do so. (Note: this Order references several provisions of a staff report dated August 29, 2001, which are not described in the Order. Perhaps the most important of these is the directive to the companies to account for hedging activities as indicated in Exhibit No. 2 of Staff's report.)</p>

State: VT
Reference: Docket No. 6596, 220 PUR 4 th 280
Date: 7/15/02
Scope: Disallowing purchased power costs as not economically useful
<p>Abstract: The Vermont Public Service Board approves \$4.8 million of a requested \$10.7 million in rate relief for Citizens Communications Company. In relevant part, the Board finds that the Company was <u>not</u> imprudent in entering into a long-term purchase contract with Hydro-Quebec in the early 1990's. Nevertheless, the Board disallows one-half of the Hydro-Quebec contract costs which are used but not economically useful (i.e., above market). According to the Board: "Committing to this long-term purchase of power made sense for Citizens in the early 1990's due to circumstances that distinguish it from other Vermont utilities, including:</p> <ul style="list-style-type: none"> • The nature of the Company's interconnections with Hydro-Quebec and Vermont transmission systems; • Citizens' pressing need for firm baseload power; and • Benefits of the Hydro-Quebec Contract power that are specific to Citizens. <p>Those unique benefits, in combination with other attributes of the Hydro-Quebec Contract power, have significantly increased the value of the power to Citizens and its Vermont ratepayers. However, even taking these unique benefits into account, the Hydro-Quebec Contract power remains materially more expensive than market power in the expected rate year. As a result, we disallow as uneconomic \$750,000, which is 50 percent of the above-market portion of the Company's cost of the Hydro-Quebec Contract power."</p>

State: WA
Reference: Docket No. UE-011595, Fifth Supplemental Order
Date: 6/18/02
Scope: Purchased power cost incentive mechanism
<p>Abstract: The Washington Utilities and Transportation Commission approves the use of an incentive mechanism, the Energy Recovery Mechanism (ERM), to recover power supply costs incurred by Avista Utilities (formerly Washington Water Power) in 2002 and beyond. (Note: Power costs incurred by Avista through December, 2001 were addressed in a settlement stipulation, approved by the Commission in March 2002, which provides for the recovery of \$196 of \$217 million in deferred costs.) The ERM provides an incentive for Avista to contain power costs below a “base” level established in the company’s last general rate case, filed in December, 2001. It establishes a +/- \$9 million “Company Band” around expenses and revenues recorded in four FERC accounts (Accounts 447-Sales for Resale, 501-Thermal Fuel, 547-Fuel, and 555-Purchased Power), and calculates the difference between actual and “base” amounts every month. Savings (actual less than base) or overages (actual greater than base) that fall within the Company Band are retained or absorbed by the Company. 90% of variations outside the Company Band are debited or credited to the deferred balance. Balances in the four FERC accounts are calculated monthly, but sharing is evaluated on the basis of annual totals. A monthly “retail revenue adjustment” is included to account for load growth and temperature affects on demand and power supply costs. This adjustment is applied as a debit or a credit to the monthly ERM deferral, depending on whether actual Kwh sales are less than, or greater than, sales assumed in base costs. In approving the Mechanism, the Commission noted that the ERM is intended to address only “ordinary” variations in power costs, not “extraordinary” variations. It quoted from the testimony of witness Norwood: “if you had a 100-million-dollar situation, then it would operate just as shown here, and that is the first nine million would be absorbed by the Company. There would be a 90 percent deferral for any amount above that, and once you hit the 27.8-million trigger, we would file with the Commission to adjust rates. If the balance continues to grow, then it would be up to the Company then to come to the Commission to say that we have an extreme extraordinary situation and request the appropriate relief at the point in time, but that would be outside of this ERM mechanism.”</p>