

*Resource Planning and Procurement:  
Case Studies of Regulatory Innovation*

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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

This report presents case studies of innovative regulatory policies designed to support new investment by providing increased regulatory certainty. Eight case studies are included; four involve members that are traditional, vertically integrated utilities operating in exclusive retail service territories (i.e., Central Louisiana Electric Company, Idaho Power Company, MidAmerican Energy Company, and Wisconsin Electric Power Company); four others involve members that are restructured utilities operating in retail access environments (i.e., National Grid USA, Portland General Electric Company, Public Service Electric and Gas Company, Southern California Edison Company).

The regulatory models described in these case studies reflect a great diversity of approaches to the need for greater regulatory certainty. All involve the procurement of resources to serve customers in increasingly uncertain operating environments. Some models are built around utilities that manage portfolios of energy resources, others are built around utilities who buy a defined product at wholesale and leave portfolio management, if attempted, to suppliers. Some models allow the utility to earn a margin on procured power, others do not. Some models are designed to support affiliate transactions, others are not.

Key lessons. Among the key lessons learned from member experiences (Table 1) are the following:

- The importance of competitively neutral procurement processes.
- The technical challenges involved in evaluating bids of dissimilar resources.
- The constraints imposed by illiquidity in derivatives markets.
- The importance of customer involvement in identifying relevant resource risks, and in setting reasonable strategies for managing such risks.
- The role of regulatory pre-approval in implementing non-cost selection criteria.
- The impact of wholesale market policies on the kinds of products bidders can supply.
- The importance of regular communications with regulatory staff to keep them apprised of changes in the market.
- The difficulty of designing incentives to minimize the cost of procured resources over time.
- The jurisdictional implications of leasing facilities, rather than buying power.

Policy principles. Other, more generic, lessons are expressed as principles appropriate to guide initiatives by other utilities in other jurisdictions. At least five such principles can be identified, as follows:

1. Develop Consensus Resource Strategies – Recognizing the new uncertainties inherent in resource planning and procurement, utilities and regulators should agree (prospectively) on what the most important resource-related uncertainties (risks) are, and how they are going to manage them.
2. Understand the Implications of Risk Management – Utilities and regulators need to understand that risk management cannot be used to minimize cost; it inevitably adds cost. For this reason, customers may want choices about the amount of risk management they're asked to pay for.
3. Provide Regulatory Commitment – Once reasonable resource strategies have been identified and agreed to (# 1), regulators should honor the recovery of associated costs in rates. The reasonableness of resource strategies, including hedging strategies, should not be subject to after-the-fact prudence review.
4. Institutionalize Regular Communications – Utilities should communicate regularly with regulatory staff. Regular meetings (e.g., regularly scheduled progress reports) can help regulators keep abreast of market developments, and avoid surprises.
5. Support New Construction – To be sustainable over the long-term, new regulatory planning and approval policies must support long-term investments in new generation and other needed infrastructure.

**Summary Table 1**

<b>Company</b>	<b>Approach/Model</b>	<b>Portfolio Mgt?</b>	<b>Use Derivatives?</b>	<b>Margin on Resources?</b>	<b>Key Lessons</b>
CLECO (LA)	Competitive RFP results support CCN application.	Yes		No	<ul style="list-style-type: none"> <li>• Need to go the extra mile for competitively neutral evaluations.</li> <li>• Bid evaluation is resource intensive, technically challenging.</li> </ul>
Idaho Power (ID)	Manage to pre-defined risk tolerances with Market Trigger when rate increases needed.	Yes	Yes	No	<ul style="list-style-type: none"> <li>• Really don't know where market prices are headed.</li> <li>• Il-liquidity limits hedging.</li> <li>• Customer involvement is a real plus.</li> </ul>
MidAmerican (IA)	Up-front rate determination for rate base projects, binding on future PUC's by law.	Yes			<ul style="list-style-type: none"> <li>• Public involvement is key.</li> <li>• Pre-approval supports the use of non-cost selection criteria.</li> <li>• Pre-approval essential for building coal.</li> </ul>
National Grid USA (MA)	Bid out customer loads, flow through resulting costs into rates. Procure every 6 mos. for small customers, every 3 mos. for large. (Default Service)	No	No	No	<ul style="list-style-type: none"> <li>• Must keep up with evolving market, procure products that work for suppliers.</li> <li>• Must communicate regularly with staff.</li> <li>• Need standard contracts.</li> </ul>
Portland General Electric (OR)	Flow procurement costs through balancing account mechanism, with sharing incentives. (Mechanism expired without being renewed.)	Yes	No	Yes	<ul style="list-style-type: none"> <li>• Hard to capture long-term planning in an incentive mechanism.</li> <li>• When sharing costs customers money, they lose interest in incentives.</li> <li>• Quality control is essential when introducing non-standard accounting.</li> </ul>
PSE&G (NJ)	Bid out POLR loads, flow through resulting costs into rates. Procure one year out for large customers, term-averaged (1-3 yrs.) for small.	No	No	No	<ul style="list-style-type: none"> <li>• Need to diversify temporally.</li> <li>• Important to reflect all procurement costs directly into customer rates.</li> <li>• Regulatory involvement &amp; quick approval is essential.</li> </ul>
SoCalEd (CA)	Pre-define acceptance criteria for procurements.	Yes		No	<ul style="list-style-type: none"> <li>• Need flexibility to respond to the market.</li> <li>• Staff need new skills re. risk concepts, metrics.</li> </ul>
WEPCO (WI)	Obtain pre-approval for affiliate lease.	Yes	No	Yes	<ul style="list-style-type: none"> <li>• Shared recognition of need for new generation helps move things along.</li> <li>• Facility leases preserve state jurisdiction.</li> </ul>

## 2.0 Introduction

Since the California energy crisis of 2000 and 2001, and the events that followed it (Enron, the flight of investors, etc.), “resource planning and procurement” – the process by which regulated utilities procure resources in increasingly volatile and uncertain operating environments, *and recover associated costs in rates* - has emerged as the centerpiece of strategies for revitalizing the Regulatory Compact and restoring investor confidence. This is because, in the midst of market restructuring, public policy (and utility business strategy) must continue to respect the need (1) to ensure adequate, reasonably priced power for customers not served by the market; and (2) to preserve the ability of regulated utilities to build and maintain essential public infrastructure by attracting private capital on reasonable terms.

In addressing resource procurement issues, utilities and regulators are challenged, essentially, to catch up with the effects of restructuring. Indeed, utility operating environments have changed far more in recent years than have the policies and procedures by which their rates are regulated. At the wholesale level, the divestiture of rate-based generating assets has made restructured utilities far more dependent on wholesale purchases than ever before. Even utilities that have remained vertically integrated have faced uncertainties about future state restructuring policy, leading many to rely on wholesale purchases rather than commit new capital to build rate based facilities. At the same time, the development of competitive wholesale markets (open access transmission, market pricing authority, the introduction of spot markets) has introduced unprecedented volatility in energy prices, leading to major new uncertainties about the optimal timing of purchases. Fuel prices also have become more volatile, at least in part because of declining fuel diversity (until recently, nobody was building anything but gas-fired generation). And then there is retail access, which has contributed new uncertainty about the loads utilities are (still) obligated to serve. All together, these effects have translated into major new planning and procurement uncertainties, that either were not present in traditional markets, or not present to the degree they are today. To catch up with these changes, utilities and regulators must find new ways to measure and manage risk, and must develop new planning and approval procedures to provide increased regulatory certainty regarding the recoverability of utility costs.

This report documents the results of first-generation attempts to meet this challenge. None is perfect, but most are working; some very well. And in most cases, investors and rating agencies view them as lowering regulatory risk – which is precisely the point. The case studies reflect both restructured and traditional utilities, demonstrating that utilities and policy makers in “closed” states are not immune from the new uncertainties, but can be challenged by the effects of wholesale restructuring, and the potential for retail restructuring.

Each case study follows a standard format that addresses:

- The company;
- The regulatory jurisdiction;
- The regulatory model that is the subject of the case study;
- Key risk mitigating features of the model;
- Operating experience with the model;
- Lessons learned by the company.

The purpose of this report, first and foremost, is to share information among members. There are lessons and insights here that undoubtedly can be applied by other members in other jurisdictions. These are indicated in the “operating experience” and “lessons learned” sections of the cases, and are summarized in Table 1 of the Executive Summary. There also appear to be broader lessons which are reflected as suggested principles to guide efforts to update regulatory planning and approval processes; these are described in Section 4.0.

The fundamental premise of this project is that regulatory policy; particularly, *state* regulatory policy, is key to restoring investor confidence. Since there are political limits to achieving risk-adjusted rates of return, the best, most practical strategy (for utilities and for policy makers) is to control regulatory risk. In this way, utilities and jurisdictions can improve their access to reasonably-priced capital. This is in the public interest.

## 3.0 Case Studies

### 3.1 Central Louisiana Electric Company

Cleco Corporation (CLECO, NYSE - CNL) is a Louisiana based energy company that owns Cleco Power; a 2,000 MW vertically integrated electric utility serving 260,000 customers in central Louisiana. CLECO's supply portfolio includes western coal, lignite, oil, and natural gas-fired generation.

Restructuring policy has been uncertain in Louisiana. Retail markets in the state remain "closed," although proposals for retail access have been pending for several years, both at the Louisiana Public Service Commission (LPSC), and at the New Orleans City Council. At the same time, significant merchant generation capacity was constructed in Louisiana as IPP's attempted to take advantage of the large regional market. The resulting capacity glut in the Entergy market and the lingering uncertainty regarding retail choice led to the subject RFP/CCN procedure being adopted in April of 2002.<sup>1</sup> The LPSC did not want its jurisdictional utilities constructing any more new capacity, in an overbuilt market, without having a thorough market testing mechanism in place. The RFP/CCN procedure was proposed by the LPSC at their December 5, 2001 Business and Executive Session.

Regulatory model. The new procedure combines a competitive Request For Proposal (RFP) process with a Certificate Of Convenience And Necessity (CCN) process. The CCN process provides formal regulatory endorsement that proposed projects are prudent before funds are committed. Results of the RFP process support CCN applications (e.g., by demonstrating that proposed projects are least-cost).

In the RFP phase, a utility seeking to build or acquire new 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. LPSC Staff (Staff) and other participants review the filing and the utility conducts one or more technical conferences, as needed, to explain its proposed procurement. 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 the CCN phase, the utility applies formally for a CCN, using the results of the RFP process to support its application. A CCN filing can be made without running the RFP process only in the following cases: (1) resources less than 35 MW, (2) modifications to an existing unit which expands the unit's capacity by less than 10 percent or 50 kW, (3) return to service of a shutdown unit if refurbishment costs are less than \$100 per kW, (4)

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<sup>1</sup> Louisiana Public Service Commission, Docket No. R-26172, 4/10/02; 217 PUR 4<sup>th</sup>, pages 201-209.

projects which increase capacity if the incremental installed capacity is less than \$100 per kW, (5) contracts for emergency or economy power, and (6) contracts of one year or less in duration, provided that the company expects to receive power under the contract within one year of the contract execution..

Key risk mitigating features. The RFP process facilitates consensus among Staff and bidders regarding the need for new resources and regarding the design of a competitively-neutral process by which a winning bidder will be selected. This minimizes the probability of subsequent legal challenges to the results of procurements. (Note: The RFP process intentionally does not create a docketed proceeding, so as to preclude litigation prior to the CCN filing stage.) To the extent that the LPSC grants a CCN to build or acquire capacity, the RFP process provides an up-front determination that the proposed procurement is prudent.

Operating experience. CLECO has used the new procedure once, and it worked well; bidders were satisfied that the procurement process was fair and the Company obtained a CCN to buy up to 760 MW of gas-fired generation. However, other utilities in the state have been accused of abusing the process (i.e., by submitting affiliate bids after the cost of competing bids was known). As a result, the procedure is under review for possible revision. A technical conference was held at the LPSC in early September, 2003, and CLECO expects the RFP rules will be amended to require hiring an independent monitor (selected by the utility) to oversee the RFP process in order to ensure that no preference is given to affiliate bidders

Bid evaluation has required more resources than CLECO expected. The one employee responsible for modeling proposals was overwhelmed due to the large number of bids received. New analytical methods had to be developed to compare bids having different lives, and involving asset sales. The company subsequently added more analytical resources to its RFP team. In one case, the Company lost about two weeks because it modeled a proposal as a take-or-pay contract, but then had to change that assumption based on input from LPSC Staff. CLECO also had to increase the storage of its computer system and add dual processing to the PC used to run the software, GenTrader, for production costing analysis.

Ensuring fuel diversity also has been an issue. Solid fuel offers have not been as prevalent and have longer lead times than gas-fired proposals. The market is inundated with gas-fueled generators in CLECO's region. The Company is looking for about 750 MW and the LPSC's consultants are advising CLECO to defer some of this, based on an expectation that building a portfolio over time is better than filling the entire 750 MW's from one RFP. Clearly, there is a lot of uncertainty about where market prices will be in the future.

Regarding financial impact, it's too early to know whether, and by how much, the new procedure might impact CLECO's cost of capital, or its access to capital. Institutional investors certainly are aware of Louisiana's new RFP general order, but they may be bothered that it will take longer to get decisions under the new procedure (i.e., complete

the evaluations and get the winner certificated). In theory, the new procedure should increase regulatory certainty and improve the Street's assessment of CLECO's exposure to regulatory risk.

#### Lessons learned.

1. The Company faces a very great burden during the RFP phase of the procedure; it must be conduct the RFP even-handedly and in a non-discriminatory manner in order to minimize certificate application challenges. This requires good project management and advance planning.
2. The use of an independent third party to monitor the RFP process and consult with Commission Staff and bidders at times when the Company is not present – has proven to be positive. This has gone a long way to reassuring bidders that the process is fair.
3. The use of a structured Q&A process, supported with a public web site, also has proven a good idea. This contributed significantly to the realization of an open and fair RFP process.
4. The Company grossly under-estimated the time and effort required to evaluate bid proposals. Adequate resources need to be allocated to bid evaluation. This includes the development of new analytic methods and tools.
5. The new procedure does provide increased regulatory certainty regarding the recovery of cost incurred to procure, or build, generating *capacity*. However, given that CLECO has a fuel adjustment mechanism, if CLECO procures resources that have high energy costs, it might still be subject to after-the-fact questions about how it dispatches them. Fuel costs related to any certificated PPA remain subject to future audit under the Commission's fuel adjustment clause General Order in Docket No. 21497.
6. Regardless of how fair the RFP process is, some merchant generators will remain inclined to intervene in certificate application filings; and possibly, to litigate. This is because generators who are in financial difficulty and who lose a bid may see litigation as the best option available to them.

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### **3.2 Idaho Power Company**

Idaho Power Company (IPC) is a 3,000 MW traditional, integrated investor-owned utility serving 426,600 customers in southern Idaho and eastern Oregon. The Company's generation mix is about 60% hydro, 30% thermal, and 10% purchased power – in an average water year.

Idaho is a “closed” state (i.e., there is no retail access/choice). Traditionally, the Company planned supply based on “median water” conditions, buying or selling power in wholesale markets to balance system load. In 1993, following seven years of drought, the Company implemented a power cost adjustment (PCA) mechanism to track power supply costs. (Power supply components of the Company's PCA include fuel, purchased power, and cogeneration and small power production less surplus sales to wholesale customers.) During 2000 and 2001 the PCA was tested severely. Stream flows were 46% of normal, and prices in western energy markets inflated to unprecedented levels. (In December, 2000 prices for mid-C tranches on peak averaged \$565, spiking at times as high as \$3,200 per MWh.) As a result, the Company's purchased power costs escalated rapidly, culminating in applications in February and March 2001 for approval to recover a total of \$227.3 million through the 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. The result was a settlement among the Company, customers, and PUC staff setting forth how the Company would manage purchased power costs going forward.

Regulatory model. On an interim basis the Company has defined market risk as the exposure to adverse movements in regional power prices in conjunction with adverse hydro conditions. The Company has identified the major factors driving variations in purchased power cost, and each year establishes risk guidelines that serve to limit the Company's market risk over a maximum 18-month period. Because the ongoing risk management activity undertaken by the Company is primarily on the behalf of its customers, the annually established risk guidelines limits reflect the desired risk tolerances, which customers, the Company, and regulators want to accept from each factor. The Company then applies hedges to limit risk to these tolerances.<sup>2</sup>

In order to establish annual limits, the Company conducts one or more collaborative workshops with staff and customer representatives (via a Customer Advisory Group - CAG) to review the resource-related risks facing the Company and its customers. The Company also solicits input from PUC staff concerning appropriate risk tolerances for the coming year. The Company then establishes consensus Risk Guidelines that define maximum amounts of risk the Company will accept from any of three sources (i.e., Tier One guidelines limit the risk arising from the total dollar exposure to changes in loads, resources and market prices from a base case called the System Risk Limit, Tier Two

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<sup>2</sup> ID PUC, Case No. IPC-E-01-16 (Phase II), Order No. 29102, 8/28/02; 220 PUR 4<sup>th</sup> page 193.

guidelines limit the risk arising from changes in the monthly load resource balance, and Tier Three guidelines limit the risk arising from potential upward price movement). If Tier One hedging activity is either very high or very low, it could indicate the limit is not well calibrated. The nature of each Tier Two or Tier Three hedge (by restricting volumetric exposure to the market) reduces the potential for a violation of the Tier One System Risk limit. In essence, because Tier Two and Three hedges help manage Tier One, they routinely eclipse the Tier One hedges that would otherwise be required by the policy so that costs do not move beyond the set tolerance level or System Risk Limit.

As the Company manages to these tolerances, it notifies the Commission and staff, in confidence, any time it enters into forward monthly contracts whose price exceeds a pre-defined Market Review Trigger. This mechanism provides the potential for the PUC to issue early consumer price signals (i.e., by adjusting retail rates) in a rising market. The Company also has organized an internal Risk Management Committee (RMC) that is separate from IDACORP (its corporate parent) to document decisions for possible audit by Commission staff.

Key risk mitigating features. Collaborative workshops at the beginning of each planning cycle produce a shared understanding (i.e., among the Company, customers, and the Commission) regarding the resource-related risks the Company is facing, and a reasonable strategy for managing such risks. The risk management strategy includes agreed-upon risk tolerances, and an early-warning mechanism (i.e., the Market Review Trigger) when tolerances are exceeded. The combination of the Trigger and regular updates on the Company's risk position ensure that there will be no surprises for the Commission. The Risk Management Committee (RMC) adds to regulatory comfort by documenting risk management decisions for possible audit by Commission staff. Use of a PCA mechanism ensures timely recovery of costs.

Operating experience. This approach has worked well. Large customers like it, and the commission likes it. The interim risk management policy may be faulted for its simplicity but it has been an excellent entry vehicle for education and customer buy in of complicated risk management principles. Although only required to meet once a year, the Company and the CAG found the collaborative process to be so beneficial that multiple workshops are scheduled throughout the year. These meetings serve four major purposes. First, to provide a forum for input from PUC Staff and customers with respect to desired risk tolerances and confirm consensus for proposed yearly Risk Guidelines. Second, provide an opportunity for CAG members to review and comment on the Company's implementation of its risk management policies. Third, the workshops provided the Company with an opportunity to enhance CAG member's understanding of various aspects of risk management. Lastly, they encourage round table discussion on how to enhance or modify the Company's risk management strategy. The Company and CAG members have been committed to making the collaborative process productive. All participants have made substantial time commitments. The Company is confident that this successful collaborative approach has served to mitigate negative regulatory hindsight reviews of the risk management activity it undertakes on the behalf of its

customers. Since it was implemented, 96-97% of IPC's eligible procured power costs (over \$500 million) have been recovered through its PCA mechanism.

Among the three major risk drivers the Company has identified, (i.e., Tier One, Tier Two and Tier Three), Tier Two has tended to dominate IPC's system. By effectively hedging Tier Two risks, the Company has been able to control overall risk to acceptable levels. The Base forecast for the 2003-04 year was established during a time of fairly low regional market prices. Prices gradually increased as regional accumulation of snow-pack trended lower than normal. Idaho Power's stream-flow forecasts since October have also trended below normal, bringing a steady stream of Tier Two purchase signals, at gradually increasing prices. Despite forecast poor hydro production and market prices higher than Base, Idaho Power was well below the Tier One limit as the year began. As time progressed the Company was exposed to further degradation of summer hydro output and to much higher summer market prices. In early 2004 the Company saw the breach of Tier One System Limit for the first time since the programs inception due to a combination of higher than planned prices and lower than expected water. To limit exposure related to these events the Company has significantly increased its hedging activity under Tier Two in order to fill the shortage caused by the poor hydro outlook.

A few years ago IPC assumed the market would provide incremental system resources, but this hasn't happened. As a result, many utilities in the Northwest now are building to meet their needs, and they are sometimes second-guessed about the kind of resources they are building or initiating RFP's for longer-term purchases. IRP has gone from being "almost history" to being back in vogue. IPC has both built new resources and acquired them through an RFP process.

Regarding financial impact, IPC cannot quantify the reduction in cost of capital, or the increase in capital access previously allowed return levels. Nevertheless, analysts are aware of this innovation and view it favorably.

Regarding the use of financial derivatives, new skill sets have been needed, including the use of new software tools to quantify market risk. Financial instruments common to other markets are unavailable to IPC due to reduced liquidity following the California energy crisis. Additional development of instruments to hedge load/volume risk is needed. Weather derivatives would be applicable, but required volumes at fair value are currently not available. Physical generating capacity, rate design, and load control remain the most feasible alternatives for managing demand risk.

#### Lessons learned.

1. The Company's culture has changed from one in which it thought it knew better than the market what future prices would be, to one in which it recognizes that the market knows best over time.
2. The Company has had to build new skills regarding risk assessment and the design and management of related hedging strategies.

3. Illiquidity in the market for derivatives is an issue; some products don't go out far enough, or are not available in discrete months.
4. The Customer Advisory Group has been a great success. Customers have become educated on the issues, and they're not bashful about recommending changes to proposed Guidelines. However, once the Group's recommendations have been addressed, the Company takes the Guidelines to its Board, and then the PUC – and it has a basis for decisions that it knows will be honored in the future. IPC thinks this is close to the ideal regulatory model.

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### **3.3 MidAmerican Energy Company**

MidAmerican Energy Company is a 4,000 MW traditional, integrated investor-owned electric and gas utility serving 681,000 electric, and 660,000 gas customers primarily in Iowa, with some customers in Illinois and South Dakota. The Company owns 4,118 MW of generating capacity, and purchases about 691 MW. The system is about 60 percent coal-fired, 23 percent natural gas-fired, and 16 percent nuclear-fueled.

From 1995-2001 the Iowa Utilities Board investigated retail access without endorsing it. (The Iowa legislature considered, but did not pass, a bill that would have required full retail access by October 1, 2002). In 1998 the Board approved a retail access pilot program proposed by MidAmerican for commercial and industrial customers. As of this writing, however, no eligible customers are participating. The Company's energy adjustment clause was eliminated in 1997 as part of an earnings-sharing (banded ROE) incentive plan.

Regulatory model. In order to remove regulatory uncertainty and provide a framework for new investment, Iowa amended its public utility code in 2001 to require, upon the request of a regulated utility, that the Iowa Utilities Board provide binding determinations regarding the ratemaking treatment to be accorded qualifying new generation projects in the state **prior** to construction of the project.<sup>3</sup>

In order for a generation project to qualify, the Board must find (1) that it will be owned or leased by a rate-regulated public utility; (2) that the facility will have a generating capacity of at least 300 MW if it is a base load facility (non base load renewable or combined cycle facilities can be of any size); (3) that the facility will be a base load facility, a combined-cycle facility, or an "alternative energy production facility" (i.e., wind, methane, solar, agricultural crops or residues, or small hydro); (4) that the facility will be located 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." Utilities can satisfy requirement # 6 through a competitive bidding process, or in some other way. The statute also provides for a procedure to pre-approve plans and budgets for controlling emissions from coal-fired generating stations.

At this time, the regulatory process is not available for power purchase contracts. The Iowa Legislature elected to encourage regulated generation construction in the state by excluding power purchases from the benefits of the process.

Key risk mitigating features. The Board specifies the rate making treatment to be accorded qualifying generation projects up-front, making substantial financial commitments. This rate determination is binding on future Boards. Moreover, the utility has discretion to decline a project if it doesn't like the terms the Board has decided upon.

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<sup>3</sup> IA, An Act Relating To Electric Power Generation and Transmission, Sec. 476.53, House File 577.

Operating experience. MidAmerican has had 3 proceedings under the new law, resulting in projects to build 790 MW of coal-fired capacity, 310 MW of wind power, and 550 MW of natural gas-fired combined-cycle capacity – all while maintaining an “A” credit rating. The regulatory and ratemaking approval process has been acknowledged by rating agencies as providing greater regulatory certainty and surety of return. \$1.4 billion is planned to build these facilities, a sum the Company says would not have been committed to generation construction absent the new process.

Customer support for all three projects has been achieved through stipulations that address ratemaking issues such as allowed return on common equity, prudence, used and useful investment, exclusion from excess capacity penalties, depreciation life, and expenditure levels not requiring a further demonstration of reasonableness (i.e., a soft cost cap). The stipulations are informal processes, not required under the legislation; but they have been effective in reducing the costs and time associated with the regulatory process. Large C&I customers, residential advocates, and organized labor have all been parties to stipulations.

Regarding wind energy projects, MidAmerican has proposed one of the largest land-based wind projects in the world (310 MW). This is over and above the 112.5 MW that MidAmerican already purchases to satisfy Iowa’s renewable portfolio standard. In the process, the Company has gained new knowledge and skill-sets about the economics of wind power construction and ownership. In particular, MidAmerican has increased its knowledge and experience regarding (1) the impact of euro-valuation/currency risk on wind projects, (2) the importance of accurate wind data for a particular site, (3) wind farm design and layout, (3) manufacturing issues, and (4) landowner agreements and easements. The Company also has become more knowledgeable about the amount of inaccurate information in the press, both pro and con, regarding renewables.

MidAmerican remains sensitive to fuel costs, since it doesn’t have a fuel adjustment mechanism in IA. Although fuel supply terms and conditions might be addressed by the regulatory approval process, no utility has requested approval of such terms and conditions, and it is uncertain how the Utilities Board would rule.

#### Lessons learned.

1. The availability of a regulatory procedure that involves all parties and regulators in the prudence, reasonableness and ratemaking principles determinations regarding a generation resource prior to making substantial expenditures or commitments is critical to reducing regulatory risk and encouraging investment in generation.
2. A process for obtaining regulatory determinations regarding prudence, reasonableness and ratemaking prior to construction is critical if a state wants to incorporate non-cost criteria into the resource selection process. Examples of non-cost criteria include favoring construction of regulated generation rather than

power purchases or favoring a generation portfolio with some renewable generation rather than all traditional generation. These types of preferences effectively change the resource selection standard from one of “least-cost” to one of “reasonable cost.” It is critical for legislators and regulators to understand the implications of such a change in the selection standard. While there generally is only one selection that is “least cost,” there can be several selections that are “reasonable cost.” To avoid placing even more regulatory risk on the utility as it selects the “reasonable cost” option, a regulatory pre-approval process is essential.

3. Iowa’s legislation has helped MidAmerican achieve new resource diversity. Without it, the tendency would be to rely upon power purchases or to construct only short construction cycle gas-fired generation to reduce regulatory, construction and financial risks. With this legislation the Company can make the long-term investments needed to develop cost-effective, longer-construction-cycle generating resources, such as coal-fired capacity.
4. The negotiation of stipulations as an alternative to contested proceedings has permitted stakeholder involvement without the delay and cost associated with litigation.
5. Another factor that has mitigated stakeholder problems is that Iowa has a separate proceeding every three years in which the Utilities Board approves MidAmerican’s energy efficiency, conservation and load management program. Stakeholders participate in that review and approval process. So, when the Company files to build new generation, it needs only to demonstrate that it has a Board-approved energy efficiency plan in place.

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### 3.4 National Grid USA

National Grid USA is a holding company whose five U.S. investor-owned electric operating companies (i.e., Massachusetts Electric, Nantucket Electric, Narragansett Electric, Granite State Electric, and Niagara Mohawk) serve more than 3.2 million electric customers in Massachusetts, New Hampshire, New York, and Rhode Island. These operating companies are restructured utilities (i.e., they have sold their generating assets and now operate as wires-only distribution specialists). National Grid also owns, maintains, and operates a 9,000-mile transmission system in the Northeast, and manages an independent transmission company that oversees a 14,000 mile transmission system in the Midwest. The Company also serves nearly 560,000 gas customers in New York.

In Massachusetts, which is the focus of this case study, retail access was implemented in 1998. At that time, Massachusetts Electric Company (MEC) implemented a settlement agreement, pursuant to which the Company agreed to provide generation service to customers not served by the market.<sup>4</sup> For existing customers, this is called *Standard Offer Service* (SOS), and is to continue through February, 2005; for new customers (or customers who go to the market and come back to regulated supply), this is called *Default Service* (DS), and has no sunset date. After SOS expires, the current rules provide that all customers not served by a retail supplier will transfer to DS. (Note: since SOS will expire soon, this case study focuses on DS procurement.)

The Massachusetts Department of Telecommunications and Energy (DTE) has, since 1998, required MEC to procure DS supply through competitive bid.<sup>5</sup> In 2003, the DTE updated its requirements, directing that MEC procure 50 percent of its supply for residential and small commercial customers in auctions every six months.<sup>6</sup> For these customers, power is to be purchased a year out. For large customers, power is purchased three months out (i.e., 100 percent of large customer DS load is procured every three months). Bid prices are flowed directly into retail rates. In addition, DS prices reflect congestion costs; large customers pay zonal congestion costs (there are three zones in Massachusetts), residential and small business customers pay a congestion cost that is averaged across all three zones. The DTE also is considering how to reflect certain additional costs (e.g., bad debt, contract administration) in DS rates.<sup>7</sup>

Regulatory model. DS supply is procured through a bidding process that is conducted via email. (A web site is being developed.) Each procurement cycle takes 70-85 days. The Company starts by issuing a request for proposal seeking load-following, all requirements service; it does this four weeks before final, binding bids are due. To be eligible, suppliers must meet credit worthiness criteria established in contracts with MEC.

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<sup>4</sup> MA DTE, Docket No. DPU 96-25-A, July 14, 1997.

<sup>5</sup> MA DTE, Docket No. 96-100, February 20, 1998.

<sup>6</sup> MA DTE, *Investigation by the Department of Telecommunications and Energy on its own Motion into the Provision of Default Service*, Docket 02-40-B, 4/24/03. See: <http://www.state.ma.us/dpu/electric/02-40/424order.pdf>

<sup>7</sup> MA DTE, Docket No. 03-88, 11/17/03.

(Bidders must post guarantees, letters of credit and/or cash.) Prices are bid on a flat monthly per kWh basis, differentiated by customer class (residential, small commercial, industrial) and by load zone (suppliers include an estimate of congestion charges, which they develop themselves). Suppliers submit “indicative bids” initially, then final bids about one week later. The Company selects winning bidders on the basis of (load-weighted) price, executes contracts with winning bidders, and then reports the results to the DTE. The Department has five business days to initiate an investigation into the winning bid prices. If it does not, the Company posts a customer notice on its website announcing the new rates, and 30 days later they go into effect.

Key risk mitigating features. Suppliers must meet creditworthiness criteria defined by contract, and post guarantees, letters of credit and/or cash - to ensure that they will prove solvent and able to perform through the term of their supply commitments. If the DTE does not initiate an investigation of winning bid prices, they are allowed to go into effect. Winning bid prices go into effect 30 days after a customer announcement is posted on the Company’s web site (i.e., costs are flowed directly into rates with no delay). There are no fuel price adjustment mechanisms; fuel price risk is borne by suppliers.

Operating experience. MEC has conducted approximately 12 auctions for DS supply. While the number and composition of the bidders has varied over time, there has not been a problem to date with lack of bidders in any of the solicitations. Bids have always been selected based on the lowest bid price for a bid that conforms to the RFP requirements. The Company has had no problem obtaining adequate security for counterparties, or evaluating a counterparty’s ability to perform. There have been no challenges by bidders of solicitation outcomes.

Regulatory commitment to pass through market prices for DS supply has been good. In 2000 and again in 2003, the DTE resisted calls by the Attorney General for an investigation when DS prices increased, because the DTE determined that the prices were provided as the result of an open and competitive process, and reflected market price for the service.<sup>8</sup>

Rating agencies have reviewed the bidding process, and received it favorably.

In terms of new skills and tools developed to implement the new regulatory policy, the Company has developed a set of spreadsheet-based models to tally the bid prices and rank them. (Note: MEC does not engage in portfolio management; this is left for suppliers to do, if they choose.) A read of the bid document and proposed contract ensures that the service being bid is consistent with specified requirements. The Company does perform a credit review of the counterparty and ensure adequate security based on the quality of the counterparty.

MEC has found that the amount of data it is sending to suppliers has increased significantly over time. In response, the Company is moving to web-based

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<sup>8</sup> MA DTE, D.T.E 00-66, 00-67, 00-70, 12/4/2000; 206 PUR 4<sup>th</sup> pages 122-133. DTE letter Order dated March 31, 2003.

communications. The proposed web design will be a simple page where would-be bidders can go to retrieve all of the information that would otherwise be transmitted via email during the RFP process (e.g., the RFP document, the proposed contract, hourly historical load data for the service being bid, number of customers enrolled in the service being bid, etc.).

#### Lessons learned.

1. For competitive bidding to work, MEC must keep up with changes in market rules, and factor this in to make sure that what it's procuring fits with the market place. In other words, the Company must request a product that works for suppliers (i.e., something they can provide). Key issues in this regard have been the following:
  - a. Locational Marginal Pricing - Since suppliers are required to make firm price bids, the introduction of LMP exposes suppliers to the risk that the *energy* portion of congestion charges – which are not known until after the fact - will cause their profit margins to be too low, or even, negative;
  - b. ICAP (installed capacity) Payments - Since suppliers are required to make firm price bids, uncertainties regarding the ICAP market, including the potential introduction of locational ICAP, mean that suppliers will be exposed to the risk that the *capacity* portion of congestion charges – which are not known until after the fact - will cause their profit margin to be zero, or even, negative;
  - c. Renewable Energy Certificates – The requirement that suppliers obtain renewable energy certificates, or make alternative compliance payments, exposes suppliers to the risk that they will not satisfy renewable energy requirements in least-cost manner. This also threatens their competitive position and/or their profit margins;
  - d. Customer Bad Debt - If suppliers are required to absorb this risk, they need the flexibility to manage it, e.g., by having discretion to terminate service.
2. It is vital to keep lines of communication to regulatory Staff open during the procurement process to avoid surprises. To the extent MEC is aware of circumstances that could affect DS supply prices, MEC meets with regulatory staff to discuss potential issues.
3. It is taking too long to negotiate individual contracts. MEC needs standardized contracts that its procurement agents can start from.

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### **3.5 Portland General Electric Company**

Portland General Electric Company (PGE) is a 4,000 MW traditional, integrated investor-owned utility serving more than 730,000 customers in Portland, Salem and nearby communities. The Company owns eight hydroelectric, and four thermal, generating stations, with a combined generating capacity of 2,022 MW. PGE buys the balance of power it needs to meet customers' load; it was the first utility in the U.S. to open its own trading floor.

Retail access for commercial and industrial customers was implemented in Oregon on March 1, 2002. PGE remains the exclusive supplier of residential customers in its service territory. Until recently, power cost adjustment mechanisms were not used in Oregon.

Regulatory model. Oregon sought to increase regulatory certainty, and encourage efficient procurement, by introducing a balancing account/adjustment mechanism that shared variations in purchased power cost between consumers and shareholders.

A power cost adjustment (PCA) mechanism tracked variances in power cost (actual vs baseline) and shared overages or savings between customers and the Company, based on a pre-defined sharing formula. Power cost variances were 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. (Note: by adjusting for energy revenue variances, the PCA balanced the revenue effects of changes in load.) Variances were calculated on a quarterly basis; the first +/- \$28 million fell within a deadband (i.e., the Company absorbed all the overage or retained all the savings), amounts over \$28 million were shared with customers in increasing proportions (i.e., from 50% for variances from \$28 - \$38 million, to 95% of variances over \$200 million).

Key risk mitigating features. The PCA mechanism provided regulatory certainty in the sense that the ratemaking treatment that would be accorded given power costs could be predicted with great accuracy. Moreover, since the PCA shared variances (above and below baseline budgets) with customers, it moderated the impact of such variances on utility earnings (i.e., it reduced risk for utility shareholders).

Operating experience. When the economy went into recession in October 2001, changes in power cost were overwhelmed by an 8% decline in load. In this context, the revenue adjustment (above) operated to protect shareholders. The result was additional revenues to be collected through the Mechanism, which caused it to lose political support. After large power cost increases in 2001, stakeholders became "positional;" they began "...looking for scalps." The Company began to encounter after-the-fact prudence challenges based on its resource decisions. (In developing a cost baseline against which to measure savings or overages, PGE had assumed a resource mix that included forward contracts. On an after-the-fact basis, the prudence of these contracts was challenged.) In effect, the Company was forced to conduct a series of mini-rate cases on power cost. The Company is presently engaged in regulatory reviews questioning the timing of its

purchases, and the reasonableness of plant maintenance and outage management practices. Moreover, by the time the Commission issued findings, PGE had already been forced to make purchases for the next year.

Notwithstanding the foregoing problems, the rating agencies liked the PCA. They liked it because it aligned revenues and costs, and because it provide coverage for negative cost exposures. A December, 2002 analysis by Moody's characterized regulatory policies in Oregon as "...supportive of the utilities' credit quality." Siting the PUC's approval of the power cost adjustment mechanism which is the subject of this case study, Moody's said: "From what we surmise of their actions to date, it appears that the utility companies will continue to receive adequate support for energy supply cost recovery."<sup>9</sup>

The Company also did make some data errors in handing off information between Customer Service and Accounting. The PCA mechanism used a formula which is not standard accounting.

The Mechanism expired in December, 2002 and was not renewed.

#### Lessons learned.

1. The PCA mechanism only incented short-term actions, it did not reward the Company for effective long-term planning. A second mechanism is needed to capture longer-term planning effects.
2. All the parties (who negotiated the Mechanism) didn't appreciate how negative circumstances could affect them.
3. When you introduce non-standard accounting, as we did in administering the PCA, you need to be sure to include mechanisms to trap errors. If you don't errors can propagate through the cost accounting/rate recovery process.

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<sup>9</sup> *Improving Liquidity For Pacific Northwest Utilities*, Moody's Investors Service, December 2002.

### **3.6 Public Service Electric and Gas Company**

Public Service Electric and Gas Company (PSE&G) is a restructured investor-owned electric and gas utility serving about 2 million electric (and about 1.6 million natural gas) customers in New Jersey, from Bergen to Gloucester counties. Although it has divested its generation, the Company arranges the procurement of about 8,500 MW for its customers who are served on PSE&G's regulated Basic Generation Service (BGS) option

Electric retail access was permitted for investor owned electric utility customers in New Jersey effective with restructuring on August 1, 1999. As part of the state's restructuring strategy, regulated rates were reduced, in steps, over the four-year transition period beginning August 1, 1999. For PSE&G, the rate reductions were accomplished through overall bill discounts provided to all customers starting at 5% in August 1999 and increasing to an average of 13.7% effective for the year beginning August 1, 2002.

The legislation underlying the restructuring in New Jersey required the electric utilities to provide BGS for three years. Before the end of that three-year period, the New Jersey Board of Public Utilities (BPU) was to determine if a competitive supply model should be implemented. In its restructuring stipulation, PSE&G established BGS prices for each rate schedule for each of the four years of the transition period, and PSE&G's electric generation plants were sold to an affiliate, PSEG Power. This affiliate to provide PSE&G the power to satisfy its BGS requirements for the first three years and was to be compensated solely by the BGS revenues realized by PSE&G. BGS for the fourth year was to be bid out by PSE&G, with the difference between procurement costs and the BGS retail revenues either deferred for recovery (if the difference was a loss), or applied to stranded cost recovery (if the difference was a gain). The three other electric utilities in New Jersey deferred their unrecovered BGS costs for the entire four years of the transition period. The recovery of deferred costs of each of the New Jersey utilities was addressed in rate proceedings that each utility was to file by August 2002, with rate recovery, in general, to commence at the end of the transition period in August 2003. As a result of these rate proceedings the other electric utilities were required to write-off some of these deferred costs.

In June 2001, the four electric utilities in New Jersey filed a generic proposal for BGS supplies for year four of the transition period that would commence August 1, 2002. In an order dated December 11, 2001 the BPU approved the proposal. Under the plan, PSE&G along with the other electric utilities in the State procured BGS supply through a state-wide, on-line auction administered by National Economic Research Associates (NERA), an economic consulting firm. Certification of auction results was to be addressed by the BPU within two days of the close of the auction. Subsequent auctions were proposed and approved for the periods of August 2003 through May 2004 and June 2004 through May 2005.

Regulatory model. The auction is described as a "simultaneous, multi-round, descending clock auction" for the full requirements load of all New Jersey BGS customers. It is

conducted in timed rounds on an internet platform. In each round, a distinct supply price is announced for each of the four New Jersey Electric Distribution Companies (EDC). Prospective BGS suppliers bid the number of tranches of load that they are willing to serve at the price prescribed for each EDC. A tranche represents a fixed percentage of each EDC's peak load for a specified customer group.<sup>10</sup> At the conclusion of bidding for each round, the supply bids for each EDCs are compared against the tranche target (i.e. what is required). Whenever the supply bid exceeds the demand, prices drop for the next round of bidding. The auction concludes when the number of supply bid for each EDC equals the tranche target.

Two auctions are held simultaneously; one to supply larger (>1500 kW) commercial and industrial (C & I) customers, and a second for residential and smaller C&I customers. Suppliers bid on the obligation to supply full-requirements load for all of the customers that remain on BGS at any time. Since customers are free to leave and return to BGS at anytime suppliers bear all of the risk of customer migration.

For the larger C&I customers (~1,200 customers, 1630 MW), the product being procured is generation capacity (in \$/MW-day) over a one-year period. Winning bidders are paid the final auction price for capacity, plus the hourly PJM locational marginal price in the EDC zone, transmission at the OATT rate, and ancillary services at a rate specified before the auction. These BGS suppliers are also paid a small option fee levied on all customers eligible for the hourly-priced rate. This fee is paid to BGS suppliers that must keep an open option to provide generation capacity for all BGS-CIEP customers, who can migrate in and out of BGS-CIEP at any time.

Supply costs for the large C&I customers are flowed through to retail rates in the form of hourly prices that mirror the supply costs. These hourly rates include components for energy at the hourly PJM LMP rate, ancillary services (¢/kWh), generation capacity (the bid product in \$/kW-month), and transmission capacity at the PJM Open Access Transmission Tariff rate ((\$/kW-month). All BGS-CIEP customers must also pay a retail margin charge of 0.5¢/kWh into a fund established by the NJBPU. All customers eligible to take hourly-priced BGS service, also pay the small option fee of 0.015¢/kWh.

The product procured for smaller C&I and residential customers is a fixed-price, full requirements supply, expressed in cents per kilowatt-hour. There is a single clearing price for each EDC that applies to all tranches for that EDC for the specified procurement term. Resources in this auction are procured on a term-averaged basis. On June 1, 2004 the EDCs will have under contract approximately one-third of their total fixed-price BGS load with a remaining contract term of one year, approximately one-third of their total fixed-price BGS load with a remaining contract term of two years, and one-third of their total fixed-price BGS load with a remaining term of three years. In subsequent years' auctions, each EDC will need to procure approximately one-third of their total BGS Load for a term of three years (starting on June 1, 2005) in order to maintain this term averaging.

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<sup>10</sup> There are two auctions for two customer groups, one for the all load of large C&I customers, and one for all other customers. These auctions and processes are described in more detail later in this section.

Supply costs for small customers (~8,620 MW) are flowed through to fixed price rates.

Key risk mitigating features. The BPU approves the entire BGS procurement process; including the auction rules, the BGS fixed-price and hourly-price contracts (which include the creditworthiness standards), and EDC specific contingency plans prior to the start of the auction.

Suppliers must agree to meet certain creditworthiness requirements to be eligible to bid, and winning bidders must post performance bonds. The BPU certifies the results of each auction in their entirety within two business days after the last auction closes. The NJBPU cannot reject prices for an individual EDC without rejecting the results of the entire auction

In the event that a BGS supplier cannot meet its obligations, BGS contracts may be assigned to other parties that comply with the creditworthiness requirements and demonstrate that they have obtained any necessary regulatory approvals.

The auction prices are directly reflected in customer rates. The larger C & I customers exposed to hourly prices, are directly billed the costs to serve them for that month. The costs for the smaller C&I and residential are recovered through fixed-price BGS rates that are developed each year after the auction, and match customer BGS billings with expected BGS payments for that year. Any actual mismatch in BGS fixed-price billings versus payments is credited to or charged to the fixed-price customers through a two-months lagging reconciliation charge.

Operating experience. The auction process has been a very positive experience for PSE&G. PSE&G derives no profit from the provision of BGS service, but neither does it bear much risk: wholesale market costs are flowed through to retail customers. The Company contracts with NERA to administer each auction, and the these administration costs are recovered from the winning bidders in the form of a tranche fee which is subtracted from their first payment The entire auction is monitored by NJBPU staff, and their consultant, Charles River Associates.

#### Lessons learned.

1. PSE&G's initial auction, which was limited by regulation, procured all BGS supply requirements for a one-year period. The Company subsequently adjusted its model so that it diversifies temporally. Using this portfolio approach, PSE&G and the other EDCs now purchase one third of the fixed price load over a three-year term each year.
2. PSE&G has developed spreadsheets that convert bid prices into tariff rates based on ratios that can be applied to the winning bid. The ratios can then be approved prior to the auction so there is no issue with respect to the level of the rates that will result from the bid and bidders can estimate migration based on their price. Thus the bids can be readily transformed into customer rates that, when applied to

metered customer usage, will result in revenues that closely approximate payments to the suppliers. In essence, this involves the use of weighting factors that take account of various rate design features (e.g., block structures, seasonal differentiation, customer load profiles). These tools have been applied by other utilities in the state.

3. In August 2003 PSE&G terminated its interruptible programs with its C&I customers as part of a settlement in its electric base rate case. Large C&I customers no longer needed a separate interruptible program since they would now essentially see spot prices through the hourly pricing. Other BGS customers and third party supplied customers are free to participate in PJM programs or those offered by the third party suppliers or other curtailment suppliers. The EDC's recognized the importance of these programs and work with PJM and the third party suppliers to promote the PJM demand response programs. PSE&G's residential appliance cycling program, which was a component of the Company's DSM program, is being continued with the capacity benefits of the program flowing to the BGS suppliers.
  
4. The New Jersey BGS procurement process is a very transparent process, and leads to healthy competition. In 2003, seventeen companies won tranches in the auctions.

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### **3.7 Southern California Edison Company**

Southern California Edison Company (SCE) is a restructured investor-owned electric utility serving approximately 4.3 million customers in central and southern California. In 1997 the Company sold its 12 gas-fired generating stations, while retaining all its hydro facilities, coal-fired, and nuclear generation. The Company continues to provide power delivery service to almost 20,000 MW of customer load. Approximately 3000 MW of this load is currently served by competitive retailers, but SCE retains a default service obligation to serve all 20,000 MW of connected retail loads.

Restructuring policy in California suffered from over-reliance on, and over-confidence in, the spot market. Retail access was implemented in April, 1998, at which time rates for residential and small business customers were reduced 10% and frozen through December 31, 2001 (or earlier if an incumbent utility has recovered all of its stranded costs).<sup>11</sup> Utilities were required to sell all of their power into, and buy all of their load-serving power out of, the California Power Exchange (PX) which operated a day-ahead hourly spot market, holding auctions and matching bids for purchase and sale. From its inception in April 1998 until May 2000, these PX spot prices were reasonably stable and on the order of \$30/MWh. However, beginning in May of 2000, average monthly PX prices began to escalate in dramatic and unprecedented fashion, peaking at over \$300/MWh during January of 2001.<sup>12</sup> Given SCE's retail rate freeze, the Company incurred approximately \$3.8 billion in net wholesale supply costs which it was not allowed to flow through to retail customers, but had to defer for uncertain future recovery.

In December 2000, generators began to refuse to sell power to SCE for fear that they would not receive payment following a settlements lag of 90 days. The U.S. Secretary of Energy issued an emergency order directing western power producers to supply power to California. These same fears were also reflected by the financial community as SCE's credit rating declined to below investment-grade. For example, Fitch's assessment of SCE's credit worthiness declined from "A" in 2000 to a low of "CCC" in 2001. In mid-January 2001, both SCE and Pacific Gas & Electric Company declared that they were financially insolvent and could not continue to purchase power pursuant to a good-faith promise that they would be capable of making payments. Faced with this dire situation, the State of California was forced to step in and procure the utilities' "residual" power requirements that could not be met by utility-retained generation. Then-Governor Gray Davis ordered the California Department of Water Resources (DWR) to begin buying this

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<sup>11</sup> CA Assembly Bill 1890, signed by Governor Wilson on September 23, 1996. Rate reductions actually went into effect 1/1/98; implementation of retail access slipped to April, 1998 because the independent system operator was not ready. See also CA PUC, Direct Access Implementation Decision 97-05-040, issued May 6, 1997; as amended by Decision 97-12-131, issued December 30, 1997.

<sup>12</sup> *California's Electricity Crisis: What Went Wrong and Why*, Dr. John Jurewitz, Southern California Edison Company, presentation to 2001 Energy and Technical Services Conference, September 9, 2001. During the summer of 2001, wholesale prices in California eased due to a combination of factors, including: declining natural gas prices, reduced consumer demand, the addition of some new generation into the market, mild summer weather, and FERC attention to potential market power abuse.

residual power to keep the lights on. The Legislature also soon authorized the DWR to enter into long-term contracts to reduce reliance on volatile and high-priced spot markets. The DWR negotiated such contracts in March and April of 2001 near the peak in forward electricity prices in the West. These contracts are of various lengths, but most do not expire until near the end of the decade (2010). The DWR also continued to purchase the remaining residual power requirements of all California investor-owned utilities out of the spot markets until the end of 2002. California utilities resumed the obligation to make these residual power purchases at the beginning of 2003.

In early 2001, the Legislature authorized the CPUC to suspend retail access. However, the CPUC did not act to do so until September, 2001.<sup>13</sup> By that time, retail access had surged back from a low of less than 1% of load to a level of about 15% of load (i.e., roughly back to its pre-crisis level) as some customers hoped to escape responsibility for paying the high prices of DWR long-term contracts.

In 2002, utilities sought to reach a clearer consensus as to their future procurement responsibilities and assurance of cost recovery. In September 2002, the governor signed into law a bill, AB 57, designed to restore regulatory certainty, and thereby, the commercial credit of SCE and other investor-owned utilities in the state. The regulatory policies and procedures implemented pursuant to AB 57 are the subject of this case study. On January 1, 2003, SCE and the other investor-owned utilities resumed their responsibilities to procure their residual power needs. They also assumed responsibility for dispatch of specifically allocated long-term DWR contracts. However, payments to power suppliers pursuant to these contracts remain the financial responsibility of DWR. The utilities merely act as “collection agents” that bill retail customers for the provision of this DWR power and send these funds to the DWR. (Note: Utilities do not take title to this power and re-sell it to their retail customers. Instead, DWR power is sold directly to retail customers.)

Regulatory model. The Public Utilities Commission (PUC) must review and approve utility procurement plans which define acceptance criteria for subsequent utility procurements. Transactions that meet these criteria are supposed to be approved as reasonable, and associated costs recovered timely in rates. It is expected that the CPUC will still conduct after-the-fact reasonableness reviews, but these reviews are supposed to focus on whether contracts are accurately and diligently administered and whether all available resources are dispatched on a least-cost basis. The intent is to shift the scope of regulatory review from issues of after-the-fact prudence to issues of compliance with the approved procurement plan.<sup>14</sup> These regulatory processes have yet to be fully implemented and tested in practice.

AB 57 directs the PUC to allocate DWR power procurement costs to each utility, then requires utilities to file proposed supplemental procurement plans within 60 days. Plans

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<sup>13</sup> 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](http://www.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/9812.PDF))

<sup>14</sup>CA Assembly Bill No. 57, signed into law 9/24/02; see: [http://www.leginfo.ca.gov/pub/01-02/bill/asm/ab\\_0051-0100/ab\\_57\\_bill\\_20020924\\_chaptered.p](http://www.leginfo.ca.gov/pub/01-02/bill/asm/ab_0051-0100/ab_57_bill_20020924_chaptered.p)

must address the following: (1) 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); (2) Resources To Be Procured – Definitions, and related justifications, for the products to be procured, including financial instruments; (3) Duration – The duration of the plan, including the duration, timing, and range of products to be procured; (4) RFP Process – The competitive process by which the utility will procure resources; (5) PBR - A description of any incentive mechanism the utility wishes to propose for treatment of procurement costs; (6) Acceptance Criteria – The upfront standards and criteria by which the acceptability and eligibility for rate recovery of procurement transactions 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; (7) Procedures For Updating – A procedure for updating the procurement plan; (8) Renewables – The plan must show that it will increase the renewable resources component of the portfolio by at least 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;” and (9) Risk Management Strategy – The utility’s risk management strategy, including specific measures of price stability. The PUC is directed to ensure the confidentiality of any market-sensitive information, provided that the Office of Ratepayer Advocates and other consumer groups are provided access to such information.

Key risk mitigating features. The PUC must pre-specify and commit to acceptance criteria upfront, and is barred from disallowing the costs of contracts that meet such criteria. [Note: 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. The CPUC can disallow recovery of contract costs if they are incurred in violation of least-cost dispatch of the overall resource portfolio. It also can engage independent consultants to evaluate a utility’s risk management and strategy.] 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 over-collections or under-collections 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.

Operating experience. AB 57 defined hopes and aspirations for a new regulatory structure that will be based on acceptance criteria known beforehand and limited use of individual contract pre-approvals. After-the-fact regulatory reviews are intended to focus only on compliance with these known criteria, faithfulness of contract administration, and least-cost dispatch of the overall portfolio of resources. SCE has been operating under a PUC-approved 2003 Short-Term Procurement Plan, and in December 2003, the PUC approved

a 2004 Short-Term Plan. Under these short-term plans, SCE is restricted from contracting forward any longer than 5 years.

Unfortunately, there has not yet been sufficient experience under AB 57 to judge how faithfully this new framework will be implemented. For instance, the PUC has not yet completed any reasonableness proceedings under these new rules. Consequently, there has been no experience with how the PUC will approach contract administration and least-cost dispatch. However, experience with expeditious review of quarterly compliance filings has been disappointing. Although a full year has passed, the PUC has reviewed and certified only one quarterly compliance filing for one of the three utilities.

Initially, the PUC has been considering utilities' Long-Term Procurement Plans through proceedings separate from the short-term plans. Proceedings are still ongoing and have yet to produce many concrete results. Until uncertainties regarding its customer retail base are more definitively resolved, SCE is not willing to enter into contracts with third-party suppliers exceeding 5-years. (Although retail access is currently suspended, there have been bills proposed in the legislature that would re-institute retail access under a core/non-core framework.) In fact, as part of its proposed Long-Term Procurement Plan, the Company has filed two plans with the Commission: one for procurements up to 5 years forward, the other for longer-term commitments. Until California policy makers clarify the market structure going forward (especially the rules governing the stability of the utility's customer base and assurances of cost recovery) SCE has stated that it will not make long-term commitments (other than for renewables contracts pursuant to its 20% Renewable Portfolio Standard obligation).

In anticipation of SCE resuming procurement in January 2003, SCE petitioned the PUC to allow it to negotiate a limited number of short-term contracts with suppliers and take them to the PUC for pre-approval. To expedite this PUC pre-approval process, the PUC directed SCE to convene a Procurement Review Group (PRG) consisting of non-market stakeholders and to review these contracts with the PRG before submitting them to the PUC for pre-approval. The intent of this consultation was to avoid any needless misunderstanding of facts, to allow differing viewpoints to be aired, and to expedite the process for stakeholders to obtain information in order for them to participate expeditiously in this PUC pre-approval process. These utility-specific PRGs were continued by the PUC following this initial procurement process and still remain today as a required forum for dialogue between a utility and its stakeholders. These PRGs have no decision-making authority but act as a constructive forum for dialogue and to share diverse viewpoints. Although the continuation of these PRGs has not been without controversy, the utilities continue today under obligations to periodically consult with their PRGs as to various ongoing and recently completed procurement activities and strategies.

Throughout these regulated procurement processes, the issue of maintaining confidentiality of potentially sensitive commercial information has been a recurring controversial subject. It is generally recognized that release of certain information is commercially sensitive and its release would adversely affect ratepayers. However, some

commercial parties argue that they cannot optimize the design of their supply proposals nor fully participate in the public policy debate over the kind of resources which ought to be procured without having more information released. The PUC is continuing to wrestle with these tensions regarding confidentiality.

Notwithstanding numerous remaining implementation uncertainties, the combination of AB 57 and the full recovery of the power costs deferred from the 2000-2001 power crisis have reduced perceived regulatory risk and allowed Moody's Investors Service and Standard and Poor's Ratings Service to upgrade the Company to investment grade. This occurred on or about December 4. Fitch had upgraded SCE to investment grade in November.

#### Lessons learned.

1. There is a fundamental tension between the Company's need for flexibility to respond to dynamic, rapidly changing market conditions; and the Commission's desire to micro-manage resource planning and procurement activities. It remains to be seen just how satisfactorily these tensions can be reconciled under the AB 57 framework.
2. Utilities are likely to be unwilling to enter into long-term financial commitments to serve their customers' power demands unless cost recovery for these commitments is reasonably assured by a stable and predictable customer base and clear rules for expeditious and secure cost recovery. In the absence of long-term financial commitments, it seems unlikely that any new generation will be developed. Therefore, unless certain critical policy issues are expeditiously resolved, the result may be slide toward a level of total resources inadequate to maintain system reliability.
3. Utility procurement staffs have had to be substantially increased and educated in very new skills involving risk measurement and risk management. PUC staff must also acquire new skills in order to exercise regulatory oversight over these activities. Unfortunately, State budget crises and pressures to downsize public employee payrolls may be interfering with the necessary acquisition of adequate staff and skill levels.
4. Commercially available tools to help address basic resource questions (e.g., how much to rely on forward, versus spot, markets) are not useable because they are designed for unregulated traders (i.e., who have no service obligation and are only buying and selling power to make money). Consequently, SCE has had to build its own, proprietary evaluation tools which has proved expensive and time-consuming.
5. The Procurement Review Group process established by the PUC has been a broadly constructive forum for parties to periodically engage in dialogue regarding procurement activities and strategies. It also makes it more difficult

for other parties to maintain their credibility while engaging in after-the-fact second guessing of utility decisions discussed with them before the fact.

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### **3.8 Wisconsin Electric Power Company**

Wisconsin Electric Power Company (WEPCO) is a 6,000 MW investor-owned electric generation and distribution utility serving 1.1 million customers in Wisconsin and the Upper Peninsula of Michigan. WEPCO 's fleet of 24 generating stations is 57.9% coal-fired, 24.5% nuclear, 1.8% hydro, and 0.5% oil-fired. 15.3% of WEPCO's supply is purchased. WEPCO is one of two utilities held by Wisconsin Energy Corporation (WEC); the other is Wisconsin Gas Company. Together, these two utilities now do business under the brand name We Energies.

Wisconsin remains a "closed" state for electricity (i.e., electric retail access has not been implemented). In 1997 the Wisconsin Public Service Commission (PSC) determined that maintaining reliability and building a robust wholesale market will remain its objectives for the foreseeable future. Native load is expected to grow 2.5 percent per year through 2011.<sup>15</sup> The state's budget for fiscal-year 2000 included provisions requiring utilities in Wisconsin to divest their transmission assets and join a Wisconsin independent transmission company, the American Transmission Company (ATC), and requiring the ATC to join the Midwest Independent System Operator.

Regulatory model. Pursuant to explicit legislative authority, in 2002 the PSC approved long-term leases of new generating facilities by WEPCO from an affiliate. The leases are approved in the context of a Certificate of Public Convenience and Necessity (CPCN).<sup>16</sup>

In granting a CPCN for twin 545 MW generators, and Certificates of Authority for supporting infrastructures (i.e. a gas main and transmission lines), the Commission affirmed the prudence of the facilities, including the innovative lease structure used to finance them, and pre-approved recovery of associated costs in rates, up to a fixed construction cost estimate. The facilities are being financed, constructed, and owned by PWGS LLC, a newly created WEC subsidiary. PWGS LLC is constructing and leasing the plants to WEPCO, which will operate and maintain them as its own. PWGS LLC will earn 12.7% return on equity, using a capital structure that is 53% common equity and 47% debt. This compares to WEPCO's current authorized return of 12.2%. In 6630\_UR-111 WEPCO's capital structure was authorized to be approximately the same: 53% common equity and 47% debt) (WEC had initially proposed a return on equity of 13.9%, which it reduced in negotiation with customer groups to 12.9%. The Commission authorized a 12.7% return on equity in its order.) The initial term of the lease is 25 years. Lease payments will include a current return on CWIP (construction work in progress), and will include pre-certification expenses. The facility lease uses fixed construction

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<sup>15</sup> WI PSC, *Application of Wisconsin Electric Power Company; Wisconsin Energy Corporation; and W.E. Power, LLC; for a Certificate of Public Convenience and Necessity for Construction of Two large Electric Generation Facilities, the Port Washington Generating Station, and Associated High Voltage Transmission and Natural Gas Interconnection Facilities to be Located in Ozaukee County*, Final Decision, 05-CE-117, December 20, 2002 at 17. Additional leases were approved in 2003 for the construction of two coal-based generation facilities to be located in Milwaukee County, Docket 05-CE-130. That decision is under appeal.

<sup>16</sup> Op. Cit.

costs (\$309.6 million for Unit 1, \$280.3 for Unit 2; stated in 2001 dollars), which escalate at no more than GDP price inflation until their in-service dates in 2005 and 2008 respectively. PWGS LLC is at risk for construction costs in excess of these amounts, with very limited exceptions (e. g. force majeure events). PWGS also is liable for damages at the rate of \$100,000/day, with a \$15 million cap, if the units fail to meet commercial operation deadlines. For its part, WEPCO must hold its customers harmless from any degradation in its credit rating that might result from the lease in the event of transfer of the asset to a third party. At the end of the initial lease term, WEPCO has the option to renew the lease at a discounted payment rate, terminate the lease, or even buy the facility subject to the determination of certain tax impacts.

In approving the affiliate lease, the Commission acknowledged WEC's contention "...that WEPCO will not be allowed sufficient return on a traditional rate base investment to compensate investors for the risks associated with the plant. Although the rate-based option is clearly one feasible alternative based on the evidence presented in this case, the Commission concludes that leased generation financing is in the public interest."

Key risk mitigating features. The PSC pre-approves cost recovery by approving the affiliate lease, the terms of which provide for full recovery of lease costs in the utility's rates. The PSC has unambiguous legislative authority to approve affiliate leases.<sup>17</sup> The utility has control at the end of the lease term to continue to operate the plant at a known lease payment amount or return it to the affiliate at no additional cost or risk to its ratepayers.

Operating experience. This model has worked very well, providing substantially more regulatory certainty, and somewhat better returns (albeit, realized at the holding company level), than would have been available under a business as usual approach. To get to this outcome, however, WEPCO had to listen to customers and other local constituencies, and adapt its original approach.

Beginning with its first proposal, "Power the Future," WEC worked with all of its constituencies (i.e., small utilities, munis, labor unions, the Customers First coalition). Everyone agreed there was a need for new generating capacity in the state. Originally, the Power the Future proposal was structured as an IPP/long-term *purchase power agreement*, which would have been FERC-jurisdictional (i.e., there would have been less muni and state input and control).

WEC listened to its constituencies – particularly, the Customers First Coalition – and restructured its proposal as an affiliate/long-term *asset lease*. WEC relied on inside and outside experts for support in drafting the leases. Three leases were involved for each of the units being constructed at the site: a facility lease, a ground lease, and a ground sublease. With the "Power the Future-2" proposal WEPCO is leasing the

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<sup>17</sup> Statutory authority for the Commission to approve the construction of a large-scale generating facilities through an affiliate was provided in Wisconsin's "Leased Generation Law," passed in 2001. (Wis. Stat. § 196.52(9)(a)3.)

facilities, not buying the power; so state jurisdiction is preserved. With this structure, there was a convergence of interests that garnered almost unanimous support from the Company and stakeholders. WEC also needed new legislation to authorize the leasing of an asset from an affiliate. This was achieved as part of the 2001 Wisconsin Act 16, the 2001-03 Biennial Budget Act, passed in August 2001 (see footnote # 11).

Regarding the impact on WEC's credit rating, bankers who have read the lease "feel that it is financeable." Also, Fitch notes that "the PTF strategy will ultimately lower WEC's overall business risk profile." Regarding the potential for rating agencies to impute additional debt in view of the long-term lease commitment, WEPCO tested the waters on this before going too far with it. Standard & Poor's committed on paper that they would count the debt once (i.e., at PWGS or at WEPCO). Moody's is viewing the utility and affiliate as a consolidated entity. (Note: The PSC's Final Decision approving the lease requires WEPCO to hold its customers harmless from any degradation in credit worthiness resulting from the lease if the plant is transferred to an external third party.)

#### Lessons learned.

1. To the extent there is a shared recognition that the territory or region needs additional generation resources, this creates a powerful incentive to support new regulatory frameworks that may be needed to develop such resources.
2. A facility lease, as opposed to a long-term purchase power agreement, preserves state jurisdiction and can be far more acceptable to state and local constituencies.

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## 4.0 Conclusions

Considering the diversity of regulatory approaches described in the foregoing case studies, and recognizing that this diversity reflects fundamental differences among utilities and states in terms of such factors as geography and climate, customer loads and utility system design, and legal and regulatory environments – it is an obvious conclusion that “no one size fits all” when it comes to revitalizing the regulatory compact.

Nevertheless, these case studies do suggest that there are certain generic attributes of successful reform that can be applied to guide revitalization initiatives everywhere. There are at least five such principles, which the case study participants unanimously affirm. They are as follows:

1. **Develop Consensus Resource Strategies** – Utilities and regulators need to recognize that in the new world, more than in the old, decisions and commitments need to be made on the basis of incomplete information and irreducible uncertainty. The path toward increased regulatory certainty starts with utilities and regulators working together to develop a shared understanding of what the most important sources of resource-related uncertainty (risk) are, and what a reasonable strategy for managing such risks is. “Reasonable” strategies are not optimal strategies, but strategies that make sense in the face of significant uncertainties. In this regard, a key source of uncertainty is the potential for customers to migrate back to regulated service when market prices are high. Policies that constrain customers’ (and suppliers’) ability to arbitrage between the market and regulated rates reduce uncertainty and improve utilities’ ability to do effective resource planning.
2. **Understand the Implications of Risk Management** – In developing consensus resource strategies, utilities and regulators should recognize that *risk management* and *cost minimization* are related, but separate objectives. *Risk management* stabilizes rates (e.g., by diversifying resources, diversifying the time frame for forward purchases, purchasing financial hedges), *cost minimization* optimizes supply given (certain) information about the load to be met, and the costs and operating characteristics of available resources. Both objectives are relevant for utility resource planning. However, because risk management inevitably adds cost (e.g., to model dissimilar resources, to negotiate multiple supply contracts, to pay the premiums for financial hedges), and because customer preferences for risk management vary, it’s a good idea to give customers choices about the amount of risk management they find cost-effective.
3. **Provide Regulatory Commitment** – It is vital that regulators honor costs incurred to implement consensus resource strategies. This is what investors are looking for in terms of regulatory certainty, and it is this kind of commitment that can produce significant long-term customer benefits by lowering utilities’ (risk-adjusted ) cost of capital. Once regulators and utilities have arrived at resource

strategies they both think are reasonable (# 1), regulators should honor related cost; even when, as is likely, strategies turn out, in hindsight, to be less than optimal. There may be a need for regulators to review *how* strategies were implemented, but the reasonableness of the strategies themselves, including hedging strategies, should not be reviewed after-the-fact.

4. Institutionalize Regular Communications – Utilities need procedures that ensure regular communications with regulatory staff. Markets are dynamic; things change. It should be expected that adjustments will be needed. Since regulators don't like surprises, regular communications (e.g., through scheduled progress reports) can help keep regulators apprised of market trends.
5. Support New Construction – To be sustainable over the long-term, new regulatory planning and approval policies must support long-term investments in new generation and other needed infrastructure. The Regulatory Compact was, first and foremost, an institutional arrangement that allowed large quantities of private capital to be raised (on very reasonable terms) to finance the construction of a power supply system to serve the public. The ability to get new “iron in the ground” remains the acid test for policies intended to revitalize the Compact.