# Resource Planning and Procurement In Evolving Electricity Markets

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## EXECUTIVE SUMMARY

During the 1990's, the U.S. government and many states restructured the electric industry, unbundling what had been vertically integrated utilities and introducing competition to wholesale power supply and to the provision of retail generation service. The wires businesses of transmission and distribution, as well as "safety-net" or "provider of last resort" generation services, continued to be provided by utilities regulated by the state commissions and the Federal Energy Regulatory Commission ("FERC"). To effect wholesale restructuring, FERC unbundled transmission from generation, licensed exempt wholesale generators, allowed market-based rates for the sales of bulk power in competitive markets, and pursued the development of large, regional open access transmission systems with competitive forward and spot markets. Retail restructuring, which is the current policy in 18 states and the District of Columbia, opened up retail supply to competition and generation service innovations, such as price risk management, unregulated "green" power offers, and convergence with natural gas and telephony services.[1]

Difficulties with wholesale restructuring have arisen in many areas: volatile prices, manifestations of market power abuse, huge losses for some regulated POLR providers, boom-bust cycles, poor financial performance for many suppliers, and (as a consequence of these problems) little meaningful reduction in regulatory oversight. These wholesale market problems have spilled over into several retail markets, both restructured and non-restructured. The most disastrous example of market failure was California, where between June 2000 and June 2001 wholesale market woes and a flawed retail restructuring combined to cause sustained high prices and supply imbalances in markets throughout the west. Postponements, suspensions and cancellations of retail access by several states came in the aftermath of the California crisis.

To the regulated T&D utilities with residual supply responsibilities, this unexpectedly high price volatility has meant that the power procurement process has become a complicated risk management

[1] States with ongoing retail access include AZ, CT, DL, District of Columbia, IL, MA, MD, ME, MI, NV, NH, NJ, NY, OH, OR, PA, RI, TX, and VA. CA started but has suspended retail competition. MT, OK, and WV have postponed the start dates. AK and NM have rescinded retail access laws. That comprises 18 states and DC, plus CA, which have actually opened their markets to some degree and 25 in total that have "tried" the new policy in some form.

process, often presenting managements with far more risk and demanding more attention than the delivery, infrastructure business that they hoped would be their focus after restructuring. Some state policy makers, concerned about the past price instability and the future resource adequacy in the restructured wholesale markets, are expressing a renewed interest in old regulatory tools, such as Integrated Resource Planning (IRP), which had been used in many states prior to utility restructuring. However, the utilities' risk management approaches and the regulators' IRP tend to look at the world from different points of view. Risk management seeks to reduce the potential range (or extremes on the probability distribution) of future costs of purchasing power from the wholesale markets. Particularly from a consumer protection viewpoint, the goal is to exclude undesirable, high cost spot and forward market situations. However, risk reduction has a cost – either truncating the upside along with limiting the downside, or paying a premium to avoid just the downside -- so you generally cannot reduce the expected cost and the risk at the same time. IRP is about choosing the lowest cost among alternatives of like benefits but different costs, typically where the alternatives are mutually exclusive and customized. A synthesis is needed to meet customer needs for risk management and least-cost planning in the evolving industry structure that is a hybrid of competition and regulation.

This paper describes a new regulatory compact[2] that is aimed at satisfying policy makers' goals for price stability and assured resource adequacy as well as the needs of suppliers' (independent and regulated) for financial viability and investor confidence. The goals are to reinvigorate and shape competitive markets in those areas where markets have been shown to work best, to better monitor and mitigate market power, to develop regulatory guidelines and information flow to achieve before-the-fact approval of the key aspects of procurement plans, and to enable adjustment in rules and procedures when this is warranted by the underlying market conditions. Five principles for the new regulatory compact are:

[2] The authors are not proposing any reduction of the basic constitutional protections against a taking contained in the *Hope* and *Duquesne* cases, i.e., the right of a regulated utility for a fair opportunity to earn the allowed return on (and of) capital investments made in the public interest. Rather, the issue is how to maintain such a fair opportunity in the evolving market and regulatory circumstances.

1. Achieve a greater shared understanding of the essential, ongoing procurement problem and collaborate with stakeholders in specifying the goals, risks and timeframes. Without a shared understanding by the stakeholders of the scope of the current procurement problem, the best solution (or even a good solution with reasonable benefits and risks for all parties) will be difficult to find. Coming to agreement among the various stakeholders about the problem of risk management that utilities face must come first.

2. Make a clear distinction between the methods and goals for integrated resource planning (IRP) versus risk management (RM). IRP has sought the lowest cost way of supplying the end-use energy service needs of consumers by looking at broad choices of traditional generation, fuel diversity, renewables and DSM. The increased reliance on volatile spot and forward power markets compels utilities to address risk management issues. However, risk management is not (and cannot be) a means of reducing *expected* level of costs, but rather of reducing the *variance* of the cost outcomes.[3]

3. Establish RM, IRP and total resource procurement objectives and the corresponding performance and prudence standards for each, which for RM (at least) must be before-the-fact standards. This principle reflects the traditional notion that prudence should be judged based on information available at the time of the decisions, not with the benefit of hindsight after the event. However, it also goes further: agreement should be reached between utilities, regulators, and other stakeholders before major decisions and procurement processes are undertaken, so that they can reflect appropriate public and private priorities and tradeoffs for what is desired. The procurement problem today has many more dimensions than in the past and reaching prior agreement on priorities among them reduces subsequent conflict. Most importantly, the specification of *before-the-fact* goals and standards actually makes managing risk possible, while *after-the-fact* rejection of risk management practices increases risk.

4. Investigate incentive or performance-based regulatory mechanisms that give utilities a stake in achieving procurement efficiency and that promote trust while reducing the regulatory

oversight burden. Once a set of procurement guidelines or benchmarks are articulated, it may be attractive to let utilities depart from these standards at their discretion, provided they fairly share in the success and failure of their efforts. Regulatory guidelines will inevitably be somewhat simpler than the complex situations and opportunities that occur, so some latitude to for utilities may prove to be beneficial to customers and administratively efficient.

5. Maintain a direct line of communication between regulators and utilities on the state of the power markets consistent with the degree to which prior expectations and model parameters for procurement need to be adjusted. Power markets change constantly, so procurement goals and the RM process must be dynamic. Given the unsettled nature of power market structure and regulation, most schemes for procurement and risk management will have to be modified if dramatically new market trends emerge or new regulatory policies take effect. For instance, unexpected changes in transmission policies or RTO market designs could undermine power plant expansion plans. Procurement practices and regulatory review policies must be designed to permit adaptation or redesign as circumstances evolve, without prejudice as to the reasonableness of prior decisions. Utilities cannot and should not make some mid-course corrections unilaterally, but neither can actions be delayed unduly by old fashioned regulatory lags.

These principles may not sound like radical notions, but in practice they will require new procedures that, in turn, require new expertise, possibly more staff, different modes of communication, more mid-course adjustment, and decidedly less after-the-fact recrimination. The new regulatory compact can be formed, but it will require vision to adjust a regulatory process that has not yet fully adjusted to the restructured industry it created.

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[3] An analogy we will come back to is fire insurance. Buying fire insurance does not change the average cost of home ownership, but reducing the (small) chance of catastrophic loss at the cost of the annual premium.

# CHAPTER 1: INTRODUCTION AND OVERVIEW

Twenty five years ago the supply planning problem for electric utilities primarily entailed two major challenges: load forecasting and least-cost generation expansion planning for power plants that would be built, owned and operated by the utility. By around fifteen years ago, the planning problem had expanded to encompass power purchases from qualifying facilities, unconventional generation resources (e.g., geothermal and biomass), and demand-side management. A new term, “integrated resource planning” or “IRP”, was coined to describe this expanded process.

During the 1990’s, the U.S. embarked on the policy of electric industry restructuring, which introduced competition, open markets and unregulated investment into wholesale and retail aspects of electric supply service, with the “wires” services remaining regulated by the federal and state governments. Competitive markets for bulk power generation were the first to emerge. This “wholesale restructuring” resulted from the adoption of open access transmission policies and the development of coordinated regional spot markets. “Retail restructuring,” or competition in the supply retail services arose later in 19 states and the District of Columbia.

Today, roughly a half dozen years since retail restructuring was implemented in the first few states, policy makers are stepping back from the initial enthusiasm for unfettered electric markets and taking a renewed interest in older regulatory tools, such as integrated resource planning. This reflects widespread concern after markets in the West had dysfunctionally high prices and apparent supply shortages in 2000 and 2001. Also, retail competition has not flourished in most states as well as had been hoped. Generally there has been less customer shifting to competitive retail suppliers than expected, especially among the small customers, and the shifting that has occurred has not always been stable. Customers have switched back and forth between regulated and unregulated supply. Thus, electric utility planners all across the U.S. now face many of the challenges of the past IRP era plus a host of new ones in fulfilling their procurement responsibilities.

Utilities who serve as the provider of last resort (POLR) face particularly complex resource planning and procurement challenges in states that offer retail access.[4] Currently about 45% of national retail load resides in the 18 states and the District of Columbia where some or all retail customers have the right to choose an alternative service provider. It was originally anticipated that the competitive market would take over the retail supply function for most customers after a transition period of five or ten years. Until that occurred, there would be a regulated "safety net" or provider of last resort (POLR) supply service for those customers who had not yet switched to a competitive supplier. Policy makers for retail access now recognize that these POLR services, especially for the smaller customers, are likely to remain a significant obligation of incumbent utilities for many years to come.

In the other 31 states (including the largest state CA), with about 55% of national retail load, retail access is either not now or has never been pursued. Because of open transmission access and independent power producers, utilities in many of these states do operate under a hybrid of traditional and competition-oriented regulatory policies for procurement. There is an obligation to procure the necessary resources to reliably meet their franchised retail obligations. But in these states, the planning problem has become more challenging, because decisions to build power plants must be tested against the varied and constantly changing opportunities to buy power in the wholesale market, creating heightened concerns of after-the-fact prudence reviews.

Under whichever regulatory regime utilities operate, resource procurement has become more complex because regulated investments in power plants and competitive contracts to purchase power may be imperfect substitutes for each. There are at least three key differences. First, owned generation has a much longer life than most standardized wholesale contracts. This can be a strength to the extent ownership helps to achieve resource adequacy, but it also raises the possibility of conflict over ratepayer responsibility for stranded costs in the face of shifting needs, e.g., by the unanticipated increase, or enactment, of retail switching. Second, plant ownership achieved at reasonable cost will provide a partial hedge against the volatile prices of wholesale power contracts, and it may also be useful for improving regional supply competition or reliability. Third, owning an

[4] For considerably more detail on retail access and POLR, see Frank C. Graves and Joseph B. Wharton, *"New Directions for Safety Net Service -- Pricing and Service Options,"* EEI White Paper, May, 2003.

efficient, flexible power plant allows the utility to produce either energy, capacity or ancillary services, giving it the scheduling and dispatch flexibility to meet varying load obligations at cost-based rates. These needs can also be satisfied with market-provided contracts but possibly at more uncertain costs. On the other hand, purchasing from competitive markets, when they are operating well, puts private capital markets and risk- taking firms into the role of building and operating new power plants, which was part of the original thrust of electric restructuring. The goal is meeting customer needs reliably and at reasonable cost. Finding the right combination of power supply resources has become more sensitive to the utility's and its customers' tolerance for risk and their needs for flexibility to accommodate future change. There is also exposure to possible lack of regulatory acceptance of the means and benefits of hedging, which is both new to regulatory review and can be done in many different ways.

The modern procurement problem must include a risk management analysis and decision process that is fundamentally different from least-cost supply planning and IRP. This complexity, in turn, creates the potential for highly contentious regulatory proceedings. The solutions to these complex, new problems require both new planning/analytic methods and new processes of cooperation and information sharing between a utility, its regulator, and its customers – in short, a new regulatory compact.

Chapter 2 of this paper deals with the new planning and procurement issues that stem from wholesale restructuring. Chapter 3 looks at the issues that are particular to the states pursuing retail access. Chapter 4 contrasts the three basic ways that a utility can procure needed resources: developing a portfolio of contracts, transferring the procurement job and risk to a third party by competitive solicitation, and having the utility own plants. Chapter 5 concludes the paper by describing the principles and processes of the new regulatory compact that is emerging in the procurement debate.

## CHAPTER 2: PLANNING & PROCUREMENT CHALLENGES UNDER WHOLESALE RESTRUCTURING

### A. Traditional IOU Business Model

Prior to industry restructuring, most investor owned electric utilities were vertically integrated electric power companies with generation, transmission, and distribution assets. Many utilities participated in power pools, in which the members reduced costs via joint dispatch but expansion planning was done by each utility for its integrated system. Long-term power purchases, if any, were generally made under contracts that were "cost-based." The traditional public utility business model had several characteristics that limited risk:

- An exclusive service franchise precluded entry by potential competitors, reducing the price elasticity of demand and enhancing the prospects for cost recovery in the event embedded costs turn out to be high relative to fluctuating replacement or market costs.[5]

- Financial risk management for the utility was essentially built-in under rate-of-return regulation in three respects. The long life of assets was matched to long-lived, low-risk average cost recovery; the option to petition for rate relief served as a financial "pressure valve" for unfavorable outcomes and unexpected costs, and fuel adjustment clauses served to overcome the conflict between the inherent fuel price volatility and the slow cost of service ratemaking process.

- The entitlement to cost recovery, even though subject to a prudence test, meant that when utilities made long-term commitments, creditors could be highly confident of being fully repaid, and shareholders could be confident that their investments would be subject to a limited degree of risk.

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4 Although an exclusive service franchise precludes entry by potential suppliers of electricity, it does not preclude competition from alternative energy sources, such as natural gas for heating, energy efficiency investments, and distributed generation.

As a result of this financial consistency and stability, electric utility bonds were virtually always rated investment-grade, and electric utility shares (like gas and telephone utility shares) were regarded as conservative "widows and orphans" investments.[6] The electric utility industry, in short, was widely viewed as a low risk, high credit-quality business.

While the financial side of traditional utility regulation had these positive features, there were a variety of perceived weaknesses to traditional cost of service regulation:

- Evidence in the late 1980s to mid-1990s seemed to show that the independent power sector could build gas-fired power plants and provide bulk power at least as cheaply as the traditional, regulated utilities could.

- Opportunities were limited for private capital to develop new generation resources under competitive conditions, which would have allowed the risk of adequate or inadequate returns to be born by specialized investors rather than customers.

- There was a lack of uniform, transparent, efficient forward and spot trading markets to price electricity like other commodities. Instead there was mostly non-standard, long-term wholesale contracting and regulated prices that averaged costs over long periods of time.

- Compared to telephony or some other deregulated industries, there was little innovation in the provision of new electric products and services, such as green power, demand management programs, and distributed generation. This was in part a result of the very long lifespan and low operating costs (compared to development) of the existing supply base. Customers' desire for innovation may also have been suppressed by the tradition of offering homogenized, one-size-fits-all level of high reliability and fairly low price risk to most classes of customers, regardless of their actual preferences. Interruptible and real time pricing rate programs, mostly for large customers, were exceptions.

These distinctions between a fully-regulated world and a competitive, restructured world remain valid today. We are now in a hybrid world in which expectations of having the "best of both" are commonplace, even though in reality, a hybrid may have difficulty producing the benefits of either. The challenge is to select the best of the old but know when it must be superceded by the new, to identify and prioritize among sometimes conflicting goals, and to find pragmatic means to reach the preferred ones. Such an exercise would result in what might be called a new regulatory compact. Some of the critical new circumstances that must be recognized going forward include: the industry credit crunch, wholesale market cyclicality and imperfect competition, the proliferation of wholesale market alternatives but occasional doubts about the quality of conduct and performance in those markets, and heavy reliance on natural gas-fired generation. Each of these is briefly discussed below.

## B. The Credit Crunch

After the Enron bankruptcy in December 2001, credit dried up for the wholesale energy trading, marketing and generation sector of the industry. Some distribution companies also were affected, especially those with unhedged POLR obligations. Rating agencies and equity analysts monitor utility industry risk management practices and regulatory policies, particularly as they may impact the balance sheet.[7] As a result, many generators and utilities experienced downgrades or been put on watch lists for a potential downgrade. Of the 73 companies in *Value Line*'s electric utility sample, Moody's downgraded 50 during the period January 1, 2001, through July 1, 2003. During the same period, only nine companies received upgrades. All four of the power generators in *Value Line* have been downgraded within the last 24 months, and three have been downgraded more than once.[8]

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5 Utility shares were sometimes referred to as Apseudo equities,≅ since they behaved more like bonds than stocks.

7 See, for example, Credit Crunch: Restoring Confidence among Jittery Investors, The Electricity Journal April 2003, 79-85.

8 Several of the electric companies were downgraded more than once by *Moody's* and many have had subsidiaries downgraded, too. Also, *Standard & Poor*'s downgraded 58 and 57 utilities (electric, gas, pipeline, and water companies) in the second and third quarter of 2002, respectively. During the same time period only 11 companies were upgraded. See *Standard & Poor's* Ratings Direct July 12 and October 11, 2002.

To the extent utilities are now relying on generators with low credit ratings, they are bearing the risk of ending up with an uncovered supply obligation if power markets should experience additional difficulties. For a utility operating under retail access, such defaults can leave the utility with reduced supply precisely at times when, first, it is most expensive to replace and, second, it is more likely that shopping customers will return to utility supply service. For a still-bundled utility, supplier defaults may induce allegations of inadequate reliability and/or imprudent lack of hedging. The credit crunch in trading and marketing has also impaired liquidity in the wholesale markets, reducing power purchase options available to electric utilities. Regulatory criticism of credit-exposed supply decisions is now more likely.

## C. Wholesale Market Performance

One of the key assumptions of industry restructuring was that wholesale power markets would function well and would support the development of competitive retail services and markets. That assumption is now in question. First, despite the rapid growth of wholesale product markets in most regions of the United States during the 1990s that growth came to a halt and, in fact, reversed in the months following the bankruptcy of Enron. Generation expansion continued, but trading activity fell off precipitously as virtually all of the major players in electricity trading and marketing either sharply reduced the scale of their operations or exited the business entirely. Liquidity in the wholesale markets has dropped correspondingly. Today, trading volumes and liquidity can be so thin that purchases of a few hundred MWs by a single buyer can raise market prices. To avoid raising prices in a thin market, a large utility may have to subdivide and disperse its purchases among several brokers or agents.

Second, we have now observed a boom-bust cycle in power plant construction. It is possible that many power plants now being completed are barely worth putting into service due to excess regional capacity expansion, transmission constraints, high gas supply costs and/or low wholesale power prices.[9] In light of this cyclicality, some experts are concerned that the wholesale market may not

[9] Energy Info Source, New Plant report, Sept 26, 2002. 60% of passed plants have been halted.

provide adequately stable prices or reliable power supplies absent new market rules and compensation mechanisms.

Third, several crucial wholesale market design issues, such as the organization and policies of RTOs, remain unresolved. Moreover, even with numerous load pockets, as well as some "generation pockets," transmission capacity expansion appears to encounter resistance due to conflicts over jurisdiction, the sharing of reliability and economic benefits and cost responsibility, or NIMBY resistance. Given the controversies surrounding any major grid expansion, it is difficult to forecast when and where new lines will be built.

## D. Wholesale Market Power Concerns

The prospect of market power abuse by generators can also affect resource procurement, even where there is sufficient generation for traditional reliability levels. This problem arises because of two fundamental features of power supply and markets that were not given sufficient attention early in the restructuring design:

- There is very low demand elasticity for electricity on the part of ultimate customers, due to lack of efficient short-term price visibility and responsibility through real time communication and metering systems as well as limitations in the level of customer interest in the expected cost savings that are achievable. Following the painful experience of San Diego's customers with total exposure to market prices in 2000, state regulatory interest in exploring how to invoke more price-responsive demand has diminished, even though more controlled exposure might be extremely helpful to market performance.

- Power is not storable for long periods of time in meaningful quantities. As a result, subject to appropriate assessment of timeframes and commitments, a supplier who owns and/or controls more uncommitted supply than the region's prevailing reserve margin can be "pivotal" and may increase market prices by withholding some supply – if it has the profit incentive to do so.

There are several ways that market power concerns can affect utility procurement. First, a utility's supply acquisitions and developments, depending on the nature and duration of its commitments, may be scrutinized to see if they increase its market share of controlled, uncommitted supply in the region to levels that are deemed undesirable. At the very least, such concerns, whether well-founded or not, can significantly increase the complexity of gaining regulatory approval for the new supplies, even if they have very attractive, low costs. Second, the potential exercise of market power by wholesale, non-utility suppliers makes utility resource planning more difficult and the corresponding financial risk much greater. For instance, predicting future prices and volatilities is more complicated if those prices are not likely to be the result of healthy competition. Third, the perception that the regional market is dysfunctional may cause regulators to conclude that wholesale power may not be "just and reasonably" priced. In effect, regulators (and customers or interveners) may hold the utility responsible for high prices, even if the utility is really the victim of market power abuse by others. Alternatively, regulators may expect the utility to have recognized market failures in advance and to somehow delayed, hedged, or otherwise avoided their adverse consequences. Reaching agreement with regulators on the sufficiency of indicators that the wholesale market is working well enough to be a significant source of utility supply will help prevent hindsight criticisms of this kind.

## E. <u>Prudence Challenges Due to Volatility</u>

The diversity of power supply choices following restructuring, combined with the volatility in wholesale power markets, creates a much higher degree of exposure to after-the-fact regulatory risk of cost disallowance. Because wholesale generation prices are so volatile, even small differences in the timing of power supply acquisition can result in large differences in the cost of purchased power. Without a process for the pre-approval of procurement policies, electric utilities may be vulnerable to hindsight criticism of procurement decisions.

Figure 1 illustrates this problem, portraying the "roller coaster" forward price of power contracts at the California-Oregon border for delivery in the $4^{th}$ quarter 2001 (4Q2001). During the sixteen months preceding the contract start date (Oct. 1, 2001), the price first climbed by a factor of almost four, from around $75/MWh to around $300/MWh, over three months and then dropped over four months by over 80% to below $50/MWh. Power at other western hubs for 4Q2001 followed a similar pattern. While this chart covers the time during and immediately after the California Crisis and represents the extreme of what can happen, shorter term price spikes are not unusual and unknown to other regions, and even a few "bad days" can be very costly. More importantly for the regulatory process, when market data like this are studied in hindsight, essentially any observer (or interviewer) can review the actual decisions a utility made in procuring supply and construct an alternative sequence of purchases that yields lower costs.[10] Market volatility makes this prospect almost a certainty. As a result, prudence challenges are likely to abound, with interveners presenting "alternatives" based on factual, historical data only known after the fact.

Figure 1

Forward Price of Block Power for
California Oregon Border Delivery in Quarter 4 of 2001
Trading Dates August, 2000 to September, 2001


10 I.e. it is "obvious" after-the-fact that any utility procuring 4Q2001 power should have done it in 2000 or waited until just before the delivery period. But no financial theory of hedging based on before-the-fact information will produce the strategy.

## F. Gas Dependency

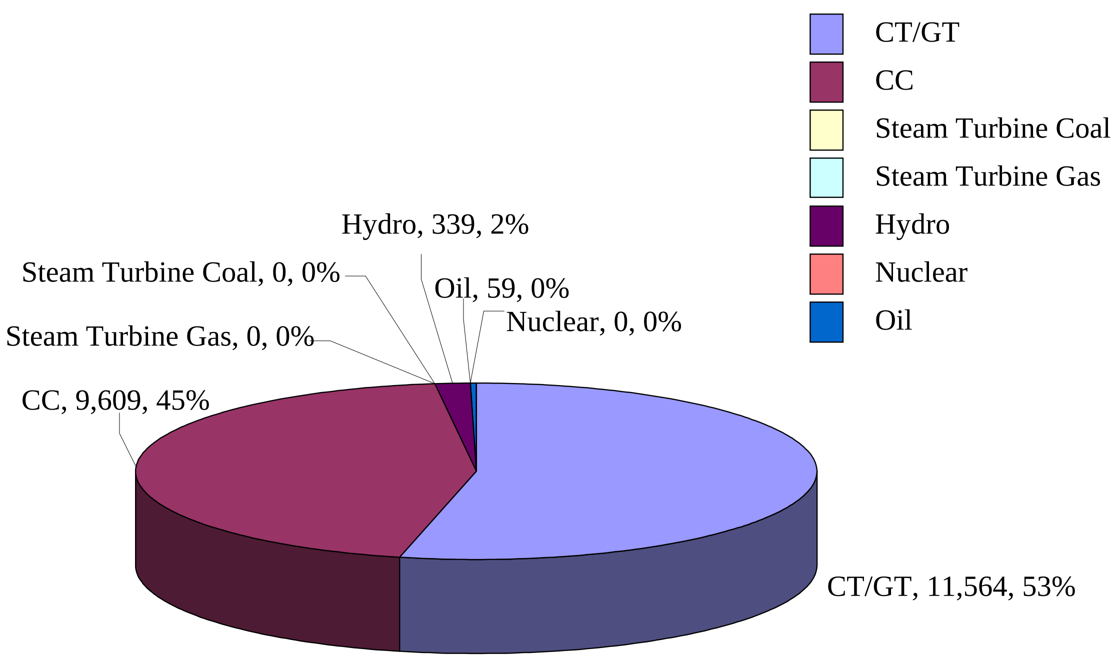
An important new aspect of power supply planning is that the generation alternatives of choice have become overwhelmingly natural gas-fired facilities, i.e., combined cycle ("CC") or Combustion Turbine ("CT") plants. While recent price increases of natural gas might blunt this trend, Figures 2A and 2B show the overwhelming dominance of these two technologies for generation installed between 1998 and 2003 in the SERC and WECC regions, respectively. Over 95% of all new capacity was of one of these types (and these two regions are not usually high). Almost the only other source of non-gas supply expansion has been improvements in the availability of nuclear and coal-fired plants and new hydro and renewable supply.[11]

Figure 2A

Breakdown of New Generation by Technology

SERC Region

1998-2003



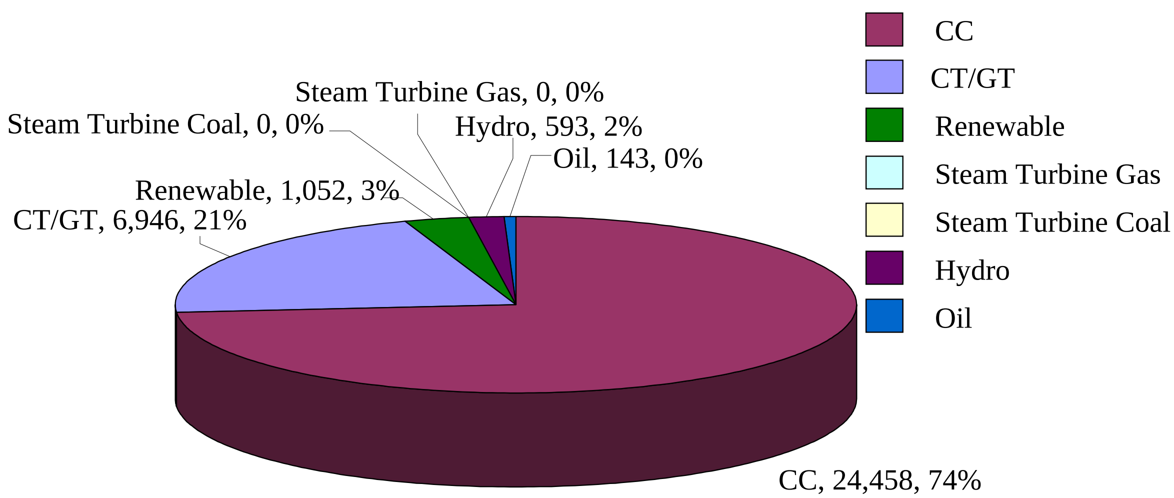

[11] Very recently, there have been a few new coal plants slated for coal-supplying regions, such as Kentucky.

Figure 2B

Breakdown of New Generation by Technology

WECC Region

1998-2003



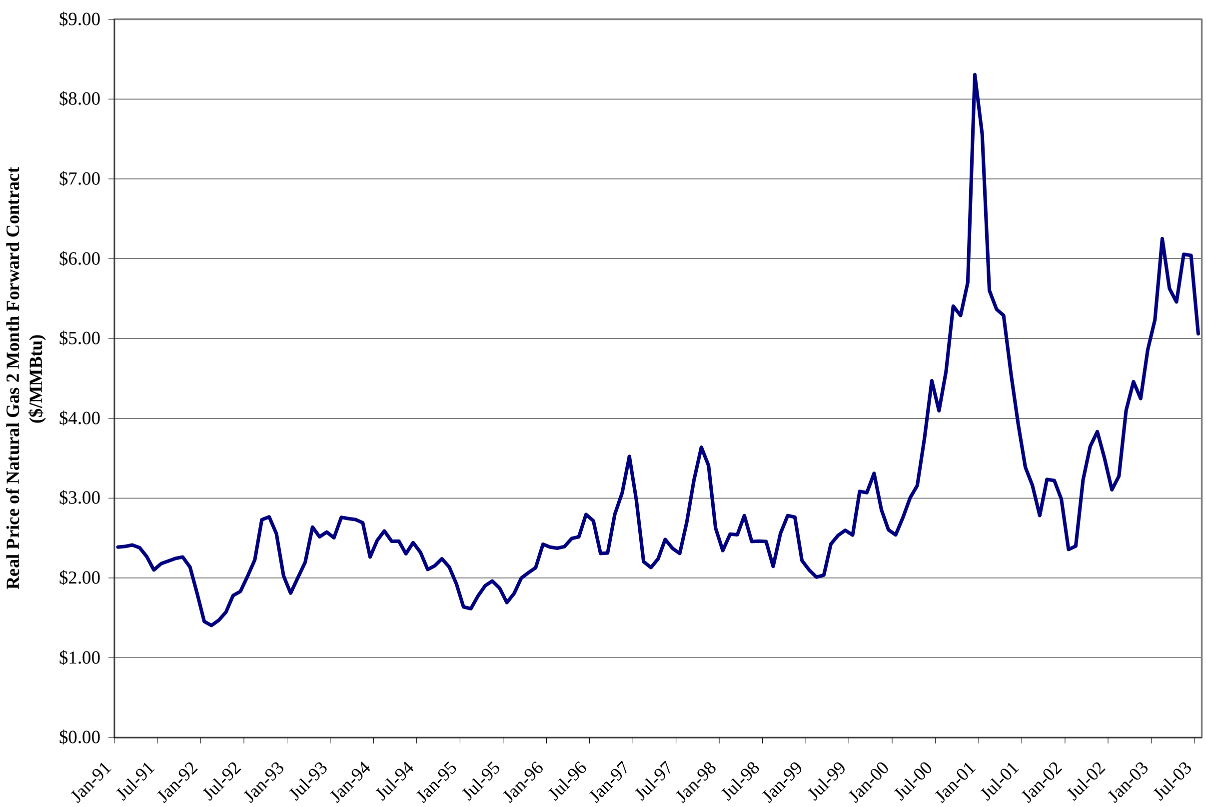

The overwhelming shift to gas has increasingly resulted in natural gas plants setting the marginal (market) price of power, exposing the utility and its customers to the gas supply prices themselves. As shown in Figure 3, gas prices in real terms have risen to more than two-fold from the levels that prevailed in the 1990's, and they have become more volatile, so the level of their relative advantage over other generation technologies may have been diminished. However, gas-fired combined cycle plants with their environmental and operating benefits still have strong economic merits.

For utility supply planners, this has created two new issues. One is whether to hedge the cost of gas, so that the utility's costs from owned generation or tolling agreements will be more stable. Another is that utilities are being asked in some states to diversify their supply portfolio away from gas towards non-conventional resources, such as renewables. Some utilities now face obligations to supply a double digit percentage of their power from renewables by as early as 2010. State policy makers may determine that this is socially beneficial, but they should consider the means to achieve it carefully, including regulatory assurances that the ratepayers will be fully responsible for the costs (which may involve subsidies). Regulators should also consider that non-conventional resource requirements can put utilities at a competitive disadvantage vis-à-vis publicly and cooperatively owned utilities that are not subject to such requirements.

Figure 3

Real Price of NYMEX Henry Hub Gas Contract

June 1991- July 2003




Notes:

Monthly average of forward contracts with 2 months remaining until delivery date.

Adjusted to $ 2003 with the Producer Price Index – All Commodities.

## G. Integrated Resource Planning Redux

Given the difficulties experienced in restructured markets, there is a heightened debate over the goals and regulatory review policies for utility planning of its generation supplies. Some are advocating a return to the procedures and standards that prevailed a decade ago under Integrated Resource Planning ("IRP"). Unfortunately, the market changes since restructuring began have rendered the old IRP model inadequate for today's power supply planning process. In particular, the old IRP model generally did not incorporate risk management considerations akin to those now central to utility planning. Perhaps a few scenarios were evaluated, but there was no need to measure and manage dynamically shifting probability distributions for future market prices or utility costs. There was also much less need to debate planning horizons, to consider customer tastes for risk, or assess the feasibility of relying on open market procurement. These new issues raise questions about the goals of utility power procurement, and they may require new planning techniques, procurement processes, and faster, more flexible regulatory approvals.

Beyond the question of which types of resources are preferred, the procurement process is increasingly being scrutinized to determine whether it involves any degree of affiliate favoritism. There are guidelines, such as the *Edgar* standards, for establishing when an affiliate offer is acceptable, but given the occasional illiquidity of the market and the customization of supply arrangements, identifying "comparables" can be a subtle issue. Concerns about affiliate favoritism have become much more contentious in the past few years. There is a natural tension between the wholesale generation sector of the industry that is likely to prefer periodic open market procurement and utilities who may be more concerned with rate stability, supply reliability, and their own cost certainty, which affiliated generation may seem to better serve. There is no simple solution; regulated utilities must search for the lowest cost supplies and reach regulatory agreement (ideally before-the-fact) about when and why the market will be used (or not). They should also strive to be explicit and non-discriminatory about how market offers are to be solicited and evaluated.

## H. Risk Management vs. Integrated Resource Planning

It might seem that today a utility could develop a power procurement plan based on a least-cost decision criterion, much as it did in the past. After all, customers always prefer lower costs, everything else being equal. Unfortunately, it is no longer the case that everything else is equal over the wide range of alternatives a utility must now consider. In particular, there is a trade-off between price certainty and resource flexibility. Since the future is uncertain, the procurement plan that really has the lowest cost cannot be known until after the fact. Spot market prices might end up costing less than a contracted-for price, but relying on such a volatile supply source for power would expose ratepayers, creditors, and shareholders to very considerable, before-the-fact risk. Thus, a power procurement program that mitigates much of the spot market risk is generally preferable even if it can ultimately lead (in some scenarios) to higher realized costs.

Several risks facing utilities and their customers, creditors, and shareholders need to be managed. These are determined first by the composition of the power supply portfolio; second, by input fuel prices; third, by retail service design and rate structure (including customers' rights to switch between services or service providers); and fourth, by how rates and services will be revised in the future in response to changes in costs and other factors. Regulation plays a major role in limiting and allocating these risks inherent in production and consumption decisions. By simply requiring or encouraging long-term asset procurement or development (rather than short to mid-term contracting), regulators are shaping the type of risk exposure that must be managed over time. For instance, decisions authorizing utilities to build power plants significantly reduce the capital-component of future supply cost-risk, but they also expose the utility to the fuel and environmental risks of the chosen type of asset for decades to come. Changes in regulation also create risk. Irreversible utility decisions that make sense under one regulatory framework might not make sense if regulations change. Uncertainty about rights and obligations is likely to undermine the credit quality of electric utilities, thereby increasing costs or decreasing reliability of service.

The “right” amount of risk-bearing for customers (in rates) is not self-evident. The aversion or tolerance for risk probably varies across customer classes and between customers within the same class. Some consumers are able to bear risk associated with future power costs easily. Others are likely to prefer rate stability to lower costs. Traditional utility practices do not permit differentiation between customers based on risk aversion. Indeed, retail access was supposed to provide that differentiation as one of its benefits, but the needed institutions and skills have not developed as hoped. Unless customers are offered a menu of services with different risk characteristics—e.g., short-term or long-term commitments, fixed or indexed prices—utility managers and regulators will have to find another way to ascertain the right tradeoffs. Meanwhile, these choices are implicitly made for customers by utility managers and regulators in their power procurement and rate design decisions.

Utility investors and creditors are less concerned with the “right” amount and allocation of risk socially than they are with earning a rate of return that compensates them for their share of that risk, and with the capital structure able to support those risks in the restructured electric business. Equity investors can bear higher levels of risk, but expected returns must be higher to compensate. The willingness of financial institutions, bond markets, and trading counterparties to extend credit will be related to the amount and quality of assets and liabilities a utility holds. Those assets and liabilities include off-balance sheet obligations and contingencies, such as power supply contracts and regulatory agreements.

The new procurement and planning problem combines traditional least-cost goals with new risk-management objectives. The methods for solving these twin problems and the standards for success under these two needs are distinct. Least-cost planning involves developing a portfolio of resources that has the lowest *expected* future cost (i.e., on average), subject to achieving a given quality of service (traditionally expressed in terms of reliability). Risk management, on the other hand, involves ensuring that the portfolio of power plants, contracts, and financial risk management instruments reduces foreseeable *variance* (or more generally, uncertainty) around the future expected cost. If the markets for hedging contracts are competitive, such agreements do *not* materially alter the expected cost of future power supply (except by their transaction cost).

This critical distinction between reducing expected costs and reducing potential variance is perhaps more evident when considering the example of home ownership and the purchase of fire insurance. The *expected* cost of owning a home is the same whether or not you purchase competitive, fairly priced fire insurance, because the fire insurance premium is the actuarially expected cost of potential fire damage. Buying insurance is just sharing the risks with other policy holders (as well as paying transaction costs to cover costs of claims adjusting, etc.). However, after-the-fact (of whether your home burns down or not), your costs will be enormously different depending on whether you are insured! The vast majority of homeowners never suffer catastrophic fire damage, which means that after-the-fact they "lose" the cost of their premium each year by buying insurance. Nonetheless, they still consider themselves better off. In contrast, utilities buying assets or taking financial positions to reduce wholesale price-spike risks may be criticized if those assets do not turn out to have been necessary to mitigate actual spikes. Correcting such misunderstandings of what to expect from risk management and how to appraise its success is a critical part of what is needed under the new regulatory compact.

The standards of regulatory review for a utility's risk management activities should be based on how the plan reduced the potential variance, especially the probability of high priced outcomes that might have ensued from a less-hedged position. Review should focus on how well the risk management plan was carried out, not on whether some after-the-fact plan (which necessarily would have had a different *a priori* risk exposure) would have been *ex post* cheaper. The latter, improper question confuses risk management with least-cost planning, even though risk management does not alter expected costs. Worse, after-the-fact reversals of risk management positions actually render them useless for genuine risk management, subsequently *increasing* the utility's risk that was dampened by the initial hedge.

Regulators have a unique and important role to play in specifying how much and what kind of risk management is to be pursued by the utility. The number of possible risk management goals and time profiles for achieving any goal is essentially unlimited. By buying forward as soon and as completely as possible under fixed terms, a great deal of price risk can be quickly eliminated, but this increases the chance that the hedged position will not fit the realized demand. By buying hedges in stages, less price risk is eliminated but the ability to fit the coverage to the realized need is increased. Hedges can lock in prices (forwards) or be one-sided (options), self-financing (collars), long-term or short, etc. There are many levels of risk reduction the utility could pursue, but there is very little pre-restructuring experience for utilities to draw upon in choosing a plan. Regulators can act as agents on behalf of customers to either specify what degree of risk protection utilities should acquire or what process of revelation/research of those desired targets utilities should pursue. Absent that clarification, it is very difficult for utilities to know how to design "prudent" risk management programs, and it is unfair to decide that after the fact.

## I. <u>Consideration of Transmission in Procurement Planning</u>

Changes in transmission access and pricing policies in pending federal legislation and at FERC add to the complexity of resource procurement. Existing transmission constraints are being factored into the price of bulk power spot sales and forward contracts. Regional transmission organizations (RTOs), such as PJM, NY ISO, and ISO New England have adopted location marginal pricing (LMP) for their spot markets, and others are considering it. While the ultimate shape and fate of FERC's Standard Market Design (or its successor incarnations) is unclear, utilities will likely have to purchase some kind of firm transmission rights (FTRs) guaranteeing that their power purchases can use the grid to reach their customers. Financial FTRs hedge adverse price impacts of transmission constraints, but they are not always available for the full life of a long-term procurement commitment. The choice of what generation resources to include in a portfolio may depend on the location of the alternatives and the assessment of the transmission system's ability to deliver the power in a variety of circumstances. Such analyses can be complicated, since the capacity of the transmission system is a variable that changes with weather, unscheduled generation and line outages, and other factors.

Transmission system capacity and operations also affect the reliability of the bulk power network, as was dramatically brought home in the Great Northeast Blackout of August 2003. Even though the locational impacts of transmission constraints are becoming monetized in the wholesale markets through FTRs and LMPs, it remains to be seen if these mechanisms will offer adequate incentives for private investors to build sufficient merchant transmission lines. The alternative (or possibly the complement) is an emerging requirement for the development of regulated transmission that would be built under the planning oversight of regional transmission organizations and recovered through regulated transmission tariffs. As resource procurement looks at long-term options, such as multi-year contracts or the ownership of new plants, many related new transmission issues will need to be carefully evaluated. Utilities may have to decide how much transmission enhancement they want to sponsor (or wait for) in their procurement programs, in order to gain access to a larger pool of competitive supplies. Alternatively, they may decide that transmission expansion is so fraught with impediments that it is best to rely on a smaller, already-accessible set of candidates, or to develop their own new power plants, and submit to more regulatory controls if that pool of alternatives is too small to be deemed competitive.

## CHAPTER 3: PLANNING & PROCUREMENT CHALLENGES UNDER RETAIL RESTRUCTURING

### A. <u>Electric Utilities after Retail Restructuring</u>

Although the experiences with retail access vary by state, it is safe to say that compared to the original hopes and expectations in the late 1990's retail competition has been slow to develop and is still an evolving policy. In almost all cases, the enabling legislation or regulatory decisions specified that the incumbent electric utilities or their affiliates[12] would continue to provide one or more regulated retail services, variously called "provider of last resort" (POLR), "safety net service," or "default service" to protect non-switching customers and thus facilitate the transition to retail competition.[13] One rough measure of the development of competitive retail markets is the extent of customer switching from the POLR offer to competitive suppliers. This measure has many drawbacks, since it varies as much or more with how POLR prices were set than with the quality or extent of retail competition, but it is followed by many retail access states.

Figure 4 shows this record for the nine retail access states that report statistics. While several other states have retail access, these nine represent the most experience with retail access (excluding CA where retail access is suspended). The size of the competitive retail market, measured as the percentage of retail load (denominated in MWh, *not* numbers of customers) with competitive suppliers, is plotted against the age of the competitive retail market, measured in the years since retail access began (ordered from oldest to most recent). The average competitive retail market has been open for about four years and has attained a market size of 22%. The most simplistic extrapolation might conclude about 20 years are needed to complete the process. However, examining these markets individually shows that most are not growing in any regular fashion. Texas and the District of Columbia, places that initiated retail access relatively recently, have seen the most

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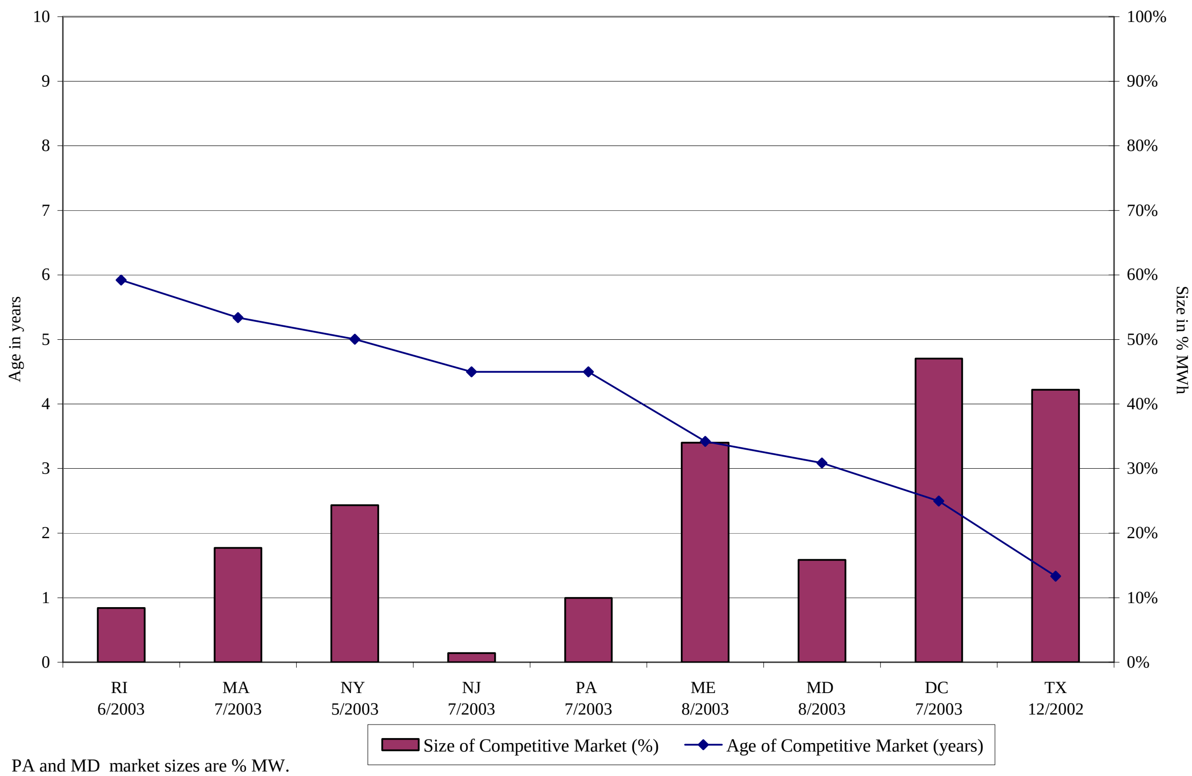
[12] New England states, such as ME, MA and RI are an exception, turning immediately to bids from competitive suppliers for the provision of all or some POLR service.

[13] See Frank C. Graves and Joseph B. Wharton, *Op. Cit.*

rapid growth of their competitive markets close to the 50% level. In other states, the clear majority of retail load is supplied under the regulated POLR offer.[14]

Figure 4

Comparing the Size and Age of Competitive Retail Markets in Selected States




PA and MD market sizes are % MW.
Sources: The Brattle Group and various state regulatory commission websites.

Existing competitive retail markets typically exhibit two recurring traits. First, the fraction of *load* that has migrated to competitive suppliers is much larger than the fraction of *customers* that migrated. This reflects the fact that the customers who switch are far more likely to be in the large commercial and industrial classes. Among the large customers, frequently the policy's strongest supporters in the beginning, retail penetration ranges from very high to small. For small commercial and residential customers, the experience has been markedly different: penetration of competitive

14 Even these results are not random samples indicating the efficiency of retail access over time, as early indicators

suppliers into the market has not been achieved to a significant degree in any state. Second, among the large customers, there have been noticeable cycles of migration to and from the competitive suppliers and the utility's POLR. So far, there is no upward, S-shaped growth curve typical of a successful new product or business development, such as the cell phone or the PC.

This mixed success in part reflects an inherent conflict of objectives in the design and terms and conditions of POLR service in most retail access states and in part the transactions costs and risks that customers see in competitive retail service. Protecting small customers from bad retail offers and/or spiking market prices during the transition period was paramount. The protections largely have taken two forms. First, regulators set stable POLR prices based on cost or through auctioning of the right to serve as the provider of last resort; this gave customers a safety-net price in the event the market proved unattractive. The second POLR protection was the right of customers to switch to and from competitive suppliers and the POLR provider. Problems arise with these well-intentioned policies when the price of the POLR services is set too low for competitive suppliers to beat, rendering the retail supply market stillborn before competition even got started. Alternatively, customers who are able to switch suppliers in the middle of a cost cycle stay with the utility's POLR services during peak or other high-price periods, and switch to competitive suppliers when market prices fall below the POLR rate.[15] This creates an arbitrage opportunity for customers who switch entirely for short-term economic gain – not because of genuine operating efficiency advantages of their competitive supplier(s). Aside from the fact that no POLR provider, or any business, could survive by buying high and selling low, the potential for arbitrage dramatically increases the risk of procuring resources. This is because POLR demand tends to shift in the same direction as near-term market prices, making deviations in both directions expensive to the supplier.[16] Liberal switching rights make demand more cyclical and the risk premium for fairly-priced POLR higher.

## B. Covering Perpetual POLR

may have a higher-than-normal regulated prices and/or more sophisticated industrial customer bases.

[15] Note that both customers and their competitive suppliers may have a shared interest in exercising the option in Safety Net Service (SNS). When near-term market prices periodically rise above the price of SNS, shopping customers paying the market (or market-index) price can lower their bills. Equally, the supplier who guaranteed its customers a fixed price can resell any released energy and capacity at a profit.

Many regulated utilities in retail access states had originally planned to exit the generation procurement business as competitive markets grew. But as was shown in Figure 4, the level of retail competition has so far only reached the level of between 5% and 50%, leaving 50% to 95% of total retail load on POLR service, particularly the vast majority of residential customers. As a result, many retail access states face the choice of whether to force (or "slam") customers to competitive suppliers or to accept that POLR service has become an extended, long-term obligation.[17] Instead of exiting the supply planning function, some utility POLR providers find that their service obligation has been extended for the foreseeable future and made somewhat more difficult by its contingent nature and its uncertain time horizon.

Given this outlook, there are good reasons for regulated utilities in retail access states to begin acquiring longer term POLR supplies. Long-term wholesale contracts or utility ownership of supply can offer POLR prices that are more stable and close to long-run marginal costs, hence reasonably efficient. However, if customers remain able to switch, there are risks to POLR providers entering very long term obligations of either kind. It is conceivable (though perhaps not likely) that an extended supply glut in the wholesale power market, coupled with a fall in natural gas prices, could drive wholesale prices far enough below utility POLR prices that substantial numbers of utility supply customers would go to alternative service providers. Similar to the beginning of retail competition with its stranded costs, substantial switching could leave utilities "holding the bag" on relatively high cost energy commitments or resources. Under these circumstances we could even see the return of a pressure for retail access in states that never started or have suspended their retail competition agendas. While a renewed surge of interest in retail access now seems fairly remote, it must be recalled that some of the supply alternatives utilities must evaluate have very long lives, *e.g.*, plants or contracts lasting decades. It is certainly plausible that retail access could be significant over such a long horizon, making utility commitments to long-lived assets risky for the utility provider.

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[16] See the related EEI papers, Frank C. Graves and James A. Read, *Residual Service Obligations Following Industry Restructuring*, 2000.

On the other hand, covering POLR with a portfolio of short and medium-term wholesale contracts is also a complex and risky task, given the proliferation of opportunities in the wholesale market. These range from standard forward contracts for one month blocks of "flat" energy to standard options to customized electricity contracts that can be tailored to particular load shapes, load uncertainty, and any contingency. However, the limited depth and liquidity of current wholesale power markets (following the Enron collapse and the credit crunch) means that the pricing of anything other than standard contracts for delivery within the next one-to-two years is not transparent.

As if wholesale price uncertainty were not enough of a problem, retail service obligations entail volumetric uncertainty as well, particularly around the most volatile peak months. The volumetric risk associated with retail services under traditional regulation has been amplified – and rendered asymmetric – by customer switching rights. Building or buying supply for such conditions is likely to require risk-control targets and to entail risk premiums that were not a part of traditional least cost planning or IRP. For instance, it may be prudent to obtain supply contracts that cover more than the expected future energy requirements of current POLR customers, to hedge the risk of prodigal customers returning to POLR precisely at a time when market prices are very high. Such purchase targets are not familiar to regulators and could easily be challenged, despite their sound economic foundations. Again, the development of the appropriate portfolio of spot market purchases, standard contracts, bilateral long-term contracts or utility-owned resources should be done to achieve low and stable costs for the consumers. This difficulty calls for increased, before-the-fact communication between regulators and utilities about goals and performance criteria.

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[17] See the EEI paper *"New Directions for Safety Net Service -- Pricing and Service Options"* by Frank C. Graves and Joseph B. Wharton for a recent review of how several states have redesigned their retail access policies and reinterpreted their POLR service obligations.

## CHAPTER 4: POSSIBLE MODELS FOR POWER PROCUREMENT

The preferred design for utility power procurement should be based on answers to several questions about the goals and complexities of alternative approaches:

1. What is the current and prospective "health" of the wholesale power market? Are there adequate reserves? Are there a sufficient number of generation suppliers with reasonable creditworthiness? Are the product markets workably competition? Is mid- to long-term resource adequacy fairly well assured? Is there an appropriate mix of different types of assets? To the extent the answers to these and similar questions are favorable, there is more reason to rely on transparent, competitive procurement processes as a reliable source of just and reasonably priced supplies. To the extent the health of the regional wholesale market is in doubt, or the utility is facing atypical circumstances or opportunities, more customized and self-developed resources may become necessary.
2. What are the critical goals for procurement over the near and longer term? These could include fostering more wholesale or retail competition, stabilizing rates, improving supplier and/or utility financial viability, increasing reliability, etc. Answers to these questions will help determine the relevant planning/procurement horizon, the types of resources to seek, and the criteria to use in selecting among the candidates. A utility cannot be solely responsible for prioritizing such goals, nor will it be capable of finding a procurement plan that assures complete success for any of them. Regulators should be involved in the *a priori* specification of goals and performance tolerances.
3. What can be done to keep regulatory oversight from creating asymmetric risks that can dissipate value, *e.g.,* by being slower, less flexible, or more political than is warranted by the complex, often fast-paced economic decisions now needed for resource procurement. Closely related is for policy makers to help determine how much of what kind of risk management utilities should pursue -- under the implication that the incurred costs will be recoverable, regardless of after-the-fact "need" for the hedges. Answers to this question will help determine when and how the regulatory commission should become involved in the planning and review process.

Electric utilities that sold their generation assets in the course of restructuring have in the past adopted one of two basic models for power procurement. Under one model, the utility meets its retail load obligations by selecting and managing a portfolio of wholesale power supply contracts, sculpted roughly to match expected needs, and then balancing differences between its realized loads and supply portfolio by buying and selling in the spot market. Under the second model, the utility transfers responsibility and risk for retail power procurement to one or more third-party suppliers, typically through an RFP or an auction process, which results in a set price for the contract duration. We refer to these as the "portfolio management" model and the "transfer" model, respectively. Both of these are consistent with the ideal that the POLR obligation is transitory.

Each model has its strengths and weaknesses. The portfolio model requires substantial skills and resources in energy trading and risk management. For companies with the necessary capabilities, this may be the best way to identify and exploit the most efficient power supplies. It allows a long-term view with long-term solutions. On the other hand, since the portfolio model typically entails a large number of diverse transactions, it also entails a high degree of exposure to regulatory risk, in particular, the risk of opportunistic prudence reviews of the sort described earlier.

The transfer model — one that appears to be gaining in popularity —has the virtue of putting much of the wholesale price risk and volumetric risk of retail electric loads on a third-party supplier. It usually has a shorter term, such as one to three years, so that results reflect near-term market conditions. Compared to the portfolio approach, it provides a degree of transparency to the procurement process, to the extent bidders can quote a single "all-in" price, in contrast to a large portfolio of contracts with many prices and terms. This model does not eliminate supplier credit risk, however, and it generally does not satisfy concerns about long-term supply adequacy. It may also result in energy supply products being more simplistic and more costly than might otherwise be feasible.

For states that have not adopted retail access and for states that see a long term POLR or bundled service obligation, there is always the third model of utility ownership of generation assets under cost of service regulation. As observed earlier in this paper, one of the attractive features of the traditional electric utility business model was the fact that long-term commitments (*e.g.*, investments in power plants) were "matched" to long-term commitments from ratepayers. Owned plants provide strong collateral for bondholders. With utilities making long-term commitments to generation assets, the issue of resource adequacy and the emergence of a boom-bust cycle in the wholesale power markets may also be somewhat mitigated.

On the other hand, if electric utilities were to move back into generation ownership in a big way, it would have negative implications for the liquidity and possibly even the viability of wholesale power markets. There could be a reduction in wholesale trading volumes and increased reluctance of merchant gencos to develop new plants. In many ways, it would also close the door on several of the valid aspirations for electric industry restructuring, especially putting supply development risks under market controls, reverting back towards the 1980's model that also became unsatisfactory. Further, even though some utilities are being authorized or encouraged to consider renewed plant ownership, the regulatory rules for making such decisions financially secure need to be fully in place. The partially restructured, hybrid environment we are in may not always be fully compatible with utility plant ownership. Bounds on the reasonable level of utility ownership in a workably competitive market are an issue that needs to be addressed.

# CHAPTER 5: THE WAY FORWARD TO A NEW REGULATORY COMPACT

Resource planning and procurement are more complex today than ever before, certainly for electric utilities in retail access states, but also for utilities in the many other states that have only wholesale competition. Since FERC unbundled the transmission grid, wholesale competitive markets have been more volatile but less liquid than many other commodity markets. Fuel prices, especially natural gas, and transmission system adequacy have become more difficult to anticipate. The generation sector appears to be subject to boom-bust cycles and credit crises. These changes create considerable stress since electric power remains a highly regulated business. In retail access states, a significant obligation to serve continues despite the fact that customers can choose alternative suppliers.

What can be done at this stage of restructuring to support wholesale competition, to provide incentives for sufficient investment by independent investors or utilities themselves, and to allow customer choice in states that choose it, while protecting the financial integrity of electric utilities? In our view the key lies in a renewed and restated regulatory compact that has several features:

1. <u>Achieve a greater shared understanding of the essential, ongoing procurement problem and collaborate with stakeholders in specifying the goals, risks and timeframes</u>. Without a shared understanding by the stakeholders of the new, complex scope of the current procurement problem, the best solution (or even a good solution with reasonable benefits and risks for all parties) will be difficult to find. Coming to agreement among the various stakeholders about the challenges of risk management that utilities face must be among the first issues to be tackled.

2. <u>Make a clear distinction between the methods and goals for integrated resource planning (IRP) versus risk management (RM).</u> IRP has sought the lowest cost way of supplying the end-use energy service needs of consumers by looking at broad choices of traditional generation, fuel diversity, renewables and DSM. The increased reliance on volatile spot and forward power markets compels utilities to address risk management issues. However, risk

management is not (and cannot be) a means of reduce *expected* level of costs but rather the *variance* of the costs.[18]

3. Establish RM, IRP and total resource procurement objectives and the corresponding performance and prudence standards for each, which for RM (at least) must be before-the-fact standards or benchmarks. This principle reflects the traditional notion that prudence should be judged based on information available at the time of the decisions, not with the benefit of hindsight after the event. However, it also goes further: agreement should be reached between utilities, regulators, and other stakeholders before major decisions and procurement processes are undertaken, so that they can reflect appropriate public and private priorities and tradeoffs for what is desired. The procurement problem today has many more dimensions than in the past, often including enhancing supply reliability, stabilizing rates, promoting retail market development, protecting (or restoring) utility financial viability, fostering wholesale competition, and supporting non-conventional resources. These goals can easily conflict, with no procurement program that improves them all. Reaching prior agreement on priorities among them reduces subsequent conflict. Moreover, the specification of *before-the-fact* goals and standards actually makes risk management feasible, while *after-the-fact* rejection of risk management practices, when anticipated risky events do not occur and hedging does not appear to have been necessary or valuable, actually increases risk.

4. Establish incentive or performance-based regulatory mechanisms that give utilities a stake in achieving procurement efficiency and that promote trust while reducing the regulatory oversight burden. -- Once a set of procurement guidelines or benchmarks are articulated, it may be attractive to let utilities depart from these standards as much as they choose, provided they share some of the success and failure of their efforts. Regulatory guidelines will inevitably be somewhat simpler than the richly complex situation actually requires, so some latitude for the utility to adjust its procurement without review, just partial sharing of outcomes, may prove to be very attractive and administratively efficient. Of course, the

[18] An analogy we will come back to is fire insurance. Buying fire insurance does not change the average cost of home ownership, but reducing the (small) chance of catastrophic loss at the cost of the annual premium.

initial design of such sharing rules is laborious, but it forces precisely the kind of communication that is necessary in any case.

5. Maintain frequent communication between regulators and utilities on the state of the power markets and the degree to which prior expectations and model parameters for procurement need to be adjusted. -- Power markets change constantly, so procurement goals and the associated RM process must be dynamic. Given the unsettled nature of power market structure and regulation, almost any scheme for procurement and risk management will have to be modified as new market performance emerges and new regulatory policies take shape. For instance, unexpected changes in transmission policies or RTO market designs could undermine power plant expansion plans. Procurement practices and regulatory review policies must be designed to permit adaptation or redesign as circumstances evolve, without prejudice as to the reasonableness of prior decisions. Utilities cannot and should not make such mid-course corrections unilaterally, but neither can they be delayed unduly from making needed changes by regulatory lags.

These principles may not sound like radical notions, but in practice they will require new procedures that, in turn, require new expertise, possibly more staff, different modes of communication, more mid-course adjustment, and decidedly less after-the-fact recrimination. The new regulatory compact can be formed, but it will require vision to adjust a regulatory process that has not yet fully adjusted to the restructured industry it created.