United States of America
Before the
Federal Trade Commission

Comments on Retail Electricity Competition Plans	FTC File No. V010003

Comments of The Electricity Consumers Resource Council ("ELCON")

Pursuant to the February 2, 2001 "Notice Requesting Comments on Retail Electricity Competition Plans" issued by the Commission in File No. V010003, the Electricity Consumers Resource Council ("ELCON") hereby respectfully submits its comments.

ELCON is a national trade association representing the interests of large industrial consumers of electricity with major facilities in virtually every state and many foreign countries. ELCON members produce a wide range of manufactured products including motor vehicles, chemicals, steel, aluminum, petroleum, paper products, industrial gases, computer chips and other electronic equipment, turbines and products for aerospace, food and agricultural products, cement, and other consumer goods.

ELCON has been a leading advocate of competitive change since 1976. ELCON's policy recommendations for a competitive electricity industry have been embodied in numerous bills proposed at the state and federal levels, and have served as guiding principles for broad, new coalitions formed to work for competitive change in electricity markets.

Comments

The Commission's inquiry is very timely and very important. More than half the states have approved the introduction of retail competition in their electricity markets. This includes the deregulation of generation and other forms of corporate unbundling by the incumbent utilities, the certification of alternative retail suppliers, and some accommodation for the utilities' so-called *stranded costs.* Retail customers in several states now have the opportunity to switch suppliers, and competition in some regional wholesale markets continues to evolve and mature. But all is not well.

In California, one of the first states to proceed down this path, the wholesale market collapsed because new generating resources were not added in Western markets to keep pace with demand growth. California's unique market design—intended to allow utilities to recover their stranded costs during a four-year transition period—proved to be a huge liability when the supply shortfall, and other contingencies, emerged. The California crisis is two-fold: it is a crisis of supply with the risk of widespread rolling blackouts now almost a daily occurrence, and it is a financial crisis that has brought two huge utilities to the verge of bankruptcy and electricity consumers face the specter as unprecedented rate increases. The crisis has created an unfortunate perception that deregulation or industry restructuring is not working, is ill conceived, and perhaps should be reconsidered or abandoned.

The reality is that the merits of deregulation and restructuring have not been disproved because the requisite market structures are not yet in place. States have been uniformly cautious with their restructuring efforts, and their initial priorities have not always been to establish competitive markets for electricity as soon as possible. Instead, states like California established a transition period that was strictly preparatory and should never have been confused with the desired end state.

California and other states will not arrive at the desired end state without committing to further changes and midcourse corrections to their preliminary market design to ensure that the objectives of a competitive power market are achieved. ELCON has launched a major initiative to distill "lessons learned" from the market collapse in the West and is preparing a set of comprehensive recommendation for state and federal regulators that are intended to prevent additional market failures from occurring. Many market design features adopted in California were copied by other states (*e.g.*, retail rate freeze). Attached, as an appendix, are a series of 18 brief position papers that deal with short-term issues. These issues include market design features that may contribute to market failure as well as short-term measures intended to prevent or correct market failures in other states or regions before competition has had a fair chance to demonstrate its worth.

The California crisis has renewed an on-going debate over the optimal design of a competitive electricity market. As a point of departure in the preparation of the 18 position papers, ELCON accepts the fact that market power—horizontal, vertical, and localized—will remain a serious impediment to market formation, perhaps indefinitely. We do not believe that policy makers in the United States will mandate the types of structural adjustments necessary to adequately mitigate market power in the electric industry.[1] Some market design features (*e.g.*, centralized exchanges with uniform-price auctions, or centralized pools with optimized dispatch) are more vulnerable to market power abuse and therefore create greater risk of market failure. We strongly urge that these market designs features be avoided. We believe more decentralized market forms, such as maximizing the use of forward markets and bilateral contracts, offer the greatest protection from market power.

ELCON looks forward to continuing a productive dialogue with the Commission and its staff.

Respectfully submitted,

The Electricity Consumers Resource Council

Washington, D.C.

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[1] ELCON has prepared a position paper outlining the structural changes necessary to eliminate market power. See *Profiles in Electricity Issues: Eliminating Market Power in the Transition to Competition*, July 1999. A copy is attached with these comments and can be downloaded from ELCON's website at: www.elcon.org/profiles.htm

Appendix

SHORT-TERM FACTORS THAT CAUSE OR PREVENT MARKET FAILURES IN THE COMPETITIVE ELECTRICITY INDUSTRY

Prepared by
The Electricity Consumers Resource Council
(ELCON)

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SHORT-TERM FACTORS THAT CAUSE OR PREVENT MARKET FAILURES

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AIR EMISSIONS STANDARDS

Generators are required to obtain emission offsets to operate in regions of the country that are not in attainment with federal air quality standards, or for new sources that may cause non-attainment. The pollutants typically associated with new fossil-fueled power plants are NO_X, VOC, PM10, SO_2, and CO. Emission Reduction Credits (ERCs) are the verifiable historic emission reductions that can be used to offset a new power plant's emissions. ERCs are tradable and where available are sold at a market-determined price. In California, the cost of an ERC (*e.g.*, a NO_X ERC in dollars per ton in 1999) may vary from a low of $913, a high of $45,000, and an average of $13,884 in the same year. However, in some markets the limited availability of ERCs—at any price—may prevent construction of new power plants. This problem restricts the use of existing stand-by generation and discourages the development of new distributed generation (DG).

Plant operators are sometime allowed to use various offset strategies to secure project permitting. These strategies include inter-pollutant, inter-sector, and inter-district/basin trading. Each of these trading strategies involves a trading ratio to account for the effect of various strategies.

The need to increase electric supply in the short run (*i.e.*, keep plants running) may also delay new retrofits that would reduce the emission credits needed to operate the plants in the long run. The inflexibility inherent with existing air quality regulations creates a dilemma for a plant operator who is forced to tradeoff the prospect of an electrical outage with the production of future ERCs.

Certainly, air quality concerns are valid, but so are countervailing economic costs associated with higher power costs and outages, and the risk to safety and public welfare. The two concerns need to be balanced. During power emergencies, the emission caps should be carefully relaxed to allow adequate short-term supply and to give generators the flexibility to plan for maintenance and retrofits.

RECOMMENDATIONS:

- Federal and state air quality laws should be rationalized with the broader societal and economic needs. Emission standards should meet a cost-benefit test that properly balances all these needs.
- Local permitting regulations should provide for greater flexibility in the manner in which offset strategies are allowed, such as inter-pollutant, inter-sector, and inter-district/basin trading. Limited exemptions from established trading ratios should be allowed during periods of power emergencies.

BANKRUPTCY

Reorganization and protection from creditors under Chapter 11 of the U.S. Code is not uncommon. Yet, the bankruptcy of electric utilities is somewhat rare. But it has occurred in recent years. The episodes involving Public Service Company of New Hampshire and the El Paso Electric Company are well known examples. In both instances the "lights stayed on." Unlike bankruptcies in other industries, where the firm may be in dire straits because the market for its products or services is no longer there, this is not the case with electric utilities. Often the problem was the political unacceptability of the rates charged to customers that the utility deemed necessary to keep it financially solvent.

Part of the dilemma is the traditional cost-plus mentality of utility management. It was and is their expectation that *any* cost they incur must be recovered from customers. The rate setting process was never immune from political influences that, most of the time, worked to the advantage of the utilities. Hence, the enormous "stranded cost" bill that is a pre-condition to any movement to a more competitive environment in which accountability is shifted to the company and its shareholders, and not simply passed on to captive "ratepayers."

But there are limits. The California Crisis was, in part, triggered by a generous accommodation of the huge stranded costs of the state's large investor-own utilities: PG&E, SCE, and SDG&E. A market structure, which was largely a by-product of the utilities' own lobbying efforts, proved untenable in the face of stresses that should have been anticipated, or planned for as plausible contingencies.

The crisis has nurtured a public debate on the appropriate role, if any, of bankruptcy protection under federal law when efforts to restructure the electric industry seemingly go awry. Bankruptcy is an unpleasant situation and for any industry charged with the "public interest," it is a potentially huge embarrassment to state regulators and other officials who are accountable, directly or indirectly, to voters.

RECOMMENDATIONS:

- Bankruptcy protection from a utility's creditors should also be an option if the alternative is to simply recover all the costs of utility mismanagement from ratepayers.
- During the transition to competitive electricity markets, regulators should set clear and unequivocal guidelines for expected utility management behavior (*e.g.*, "best business practices"). This is as much a political cover for regulators against "Monday morning quarterbacking" as it is binding obligations on utility management.

Cogeneration

The cogeneration of electric power and steam is an extremely attractive public policy perspective. The combination assures both a highly efficient and environmentally benign source of electricity and steam, and a major manufacturing facility with its employment and tax base, and other "multiplier" effects on the local and regional economy. Cogeneration units are also easier to site because they abut new or existing industrial facilities and thus lessen the local opposition typically directed at "Greenfield sites."

Yet, the planning, construction, and day-to-day operation of cogeneration units continues to face unrelenting opposition and harassment from many local electric utilities to which these units are interconnected.

Examples of abuses faced by new or existing cogenerators are onerous rates or terms and conditions of backup and ancillary services, hassles associated with a request for an interconnection study, and requirements to "dispatch" the cogenerator without regard for the physical limitations of the steam host.

During the California Crisis, owners of cogeneration were not paid for power that was injected into the grid, jeopardizing the financial viability of the generators and the steam hosts. The Cal ISO also proposed a series of actions that would require cogenerators to deliver power regardless of the physical limitations of the steam host. This risked damaging the generator or manufacturing process, and/or violating local permitting requirements.

Recommendations:

- FERC should promulgate a *pro forma* Interconnection Agreement between transmission providers and cogenerators that ensures access to regional power markets (including ancillary services) on a nondiscriminatory and comparable basis.
- FERC should require that all interconnection studies be performed by independent RTOs. This avoids the conflict of interest between a vertically-integrated utility's regulated transmission affiliate and unregulated generation or merchant affiliates.
- Emergency calls on cogenerators should be separately negotiated with each generator and its steam hosts, in the interconnection agreement, to prevent any financial, physical, or environmental harm. Any power delivered to the grid should be compensated at its full market value. Cogenerators should not be required to sell power to any entity lacking the credit to honor the transaction.

Capacity Markets and Reserve Requirements

Absent price-responsive load in the wholesale spot markets, some ISOs had to create a market for capacity that often allows generators to be paid twice for the same product. In California, this feature was easily gamed in the Cal ISO's market for replacement reserves after a suppliers' market emerged. The need for a capacity market is only justified in markets where there are barriers to entry for price-responsive load.

A capacity market is a vestige of the old regulated industry where all retail loads were captive and served on a coincident basis under average rates. Capacity reserve margins were maintained to hedge against a combination of demand uncertainty and price inelasticity. These requirements have been readily adopted or mandated in new "wholesale-only" markets.

The need for a separate market for capacity—to the extent it is needed at all—is a good measure of an imperfect market and the failure to adequately develop demand-responsive resources in real time, an original intent of industry-wide restructuring. Capacity reserve requirements have also been proposed for Load Serving Entities (LSEs) that are tasked as "providers of last resort" or POLR. Many generators that would serve such markets actively encourage their formation and seek to limit competition from retail customers that are willing to bid their load into the real-time markets (*e.g.,* with curtailable load response (CLR) service).

Recommendations:

- The retention of limited capacity reserve requirements in a transition period to more fully competitive market is justified to the extent that significant portions of retail load are served by Providers of Last Resort (POLR), and as a hedge against unforeseen consequences of new market structures. However, this should be explicitly recognized as an indicator of market failure, and *not* as a necessary feature of an end-state competitive market. Such requirements should be reduced and, eventually eliminated, as retail load gravitates to alternative competitive suppliers.
- Transitional capacity markets should be operated by independent RTOs in conjunction with their ancillary services obligations under FERC Order 2000 and the compelling need to induce retail customers to offer CLR services into the real-time spot markets.
- CLR services should have first call in any transitory RTO capacity markets (*e.g.,* operating reserves), and as markets for CLR and other forms of price-responsive loads develop, the RTO should phase out and limit access to any existing capacity markets.

Conservation and Energy Efficiency Programs

The crisis in California unequivocally demonstrated that state-sponsored conservation and energy efficiency programs could not eliminate the need to build new generating capacity to meet demand growth. No state invested more ratepayers' money toward the promotion of conservation and energy efficiency programs than California, with funding mechanisms authorized by the California Public Utilities Commission (CPUC) and often with the encouragement of the California Energy Commission (CEC). This includes the investment in renewable energy resources such as solar, geothermal, and wind generation when other resources were obviously more cost effective.

Unfortunately, the promotion of conservation and energy efficiency programs often created a false impression that such programs could obviate the need for any new traditional generating resources. Often lost in the public debate created by the California power crisis is the fact that electric industry restructuring was partially predicated on the failure of the central-planning approach to regulation that relied exclusively on least-cost planning (LCP), integrated resource planning (IRP), and demand-side management (DSM) programs to meet the basic energy needs of the consumers. It is no secret that the states that most zealously pursued these programs were the states that ended up with the highest retail electric rates and stranded cost obligations.

Recommendations:

- States always have the discretion to promote the efficient use of any natural resource, including energy. However, any state program to encourage conservation and energy efficiency should avoid creating false promises that mislead the public into believing that basic necessities are obtainable with little or no cost, and without the need to balance those objectives with other societal goals such as a clean environment and economic growth.
- The costs of any state-sponsored conservation and energy efficiency program should be borne by the consumers that directly benefit from such programs. All forms of taxation or subsidies that finance such programs, in whole or in part, should be subject to public disclosure and debate, and not hidden in arcane regulatory accounting procedures that deliberately evade public scrutiny and accountability.
- The efficient production and allocation (*i.e.,* usage) of any energy resource is best achieved in fully competitive markets. End-use consumers will maximize considerations of energy efficiency in their purchasing and investment decisions only in markets that fully compensate them for the actual cost savings hey create by their actions.

EMERGENCY SITING AUTHORITY

In 2001, both California and New York took emergency actions to expedite the siting of new generation in anticipation of severe capacity shortages during the imminent peaking season. In 1998, Wisconsin engaged in similar measures. Other states may find themselves in a similar situation if supply resources available to meet the needs of in-state loads become inadequate, or if transmission congestion is not adequately addressed and eliminated. The exact circumstances in California, New York, or Wisconsin need not be replicated to create either of these risks.

Power outages can have catastrophic consequences. Rioting and loss of life have occurred in past power outages, in addition to severe economic damages. In California, the siting of emergency generation was severely hampered by local opposition and the unwillingness to be flexible—even in a crisis—with other public policy objectives.

California initiated a proceeding to identify constraints in their siting and permitting procedures. In addition, California attempted to extract concessions from power plant developers (*e.g.*, a requirement to sell power at below-market prices) as a pre-condition to any expedited siting or permitting process.

RECOMMENDATIONS:

- States should identify and encourage any measures that streamline or expedite the siting and permitting process to enable new resources to efficiently get on line, and not have to resort to emergency procedures.
- State policies that would require owners or operators of generators to offer their power at below-market prices as a pre-condition to expedited siting or permitting treatment should be discouraged. Such policies are counter-productive and reinforce any perception that a state or locality may be hostile to generation and other investments.
- States should prepare emergency siting guidelines *before* such guidelines are needed. State legislatures should consider enacting limited waivers of air and water quality standards and land-use restrictions—including the preemption of local restrictions—during emergency situations that risk major power outages. Once an emergency has been resolved, any waivers should be rescinded and power plants that operated under such waivers should be required to comply with all air and water quality standards and land-use restrictions that are required absent the emergency.

FORWARD CONTRACTS AND RATES FOR EXISTING RATE-BASED GENERATION

California established a four-year transitional market structure that required its three major investor-owned utilities to bid all their generation into a wholesale power exchange (the "spot" market) and to purchase all power requirements needed to meet their continuing native load obligations from the same spot market.[2] The utilities were, in essence, prohibited from using long-term forward contracts to hedge against spot market price risk. California also allowed it utilities to divest generation without requiring the new owners of that generation to sign vesting contracts with the old owners for the duration of the transition period (see "Generation Divestiture and Vesting Contracts"). This would guarantee some pricing stability to remaining captive retail customers as markets were given a chance to organize and become workably competitive.

In all existing competitive commodity markets, buyers procure most, and in some cases, all their requirements under long-term bilateral contracts. Competitive electricity markets should be no different. Workably competitive markets must be decentralized to encourage producers and buyers to fairly negotiate prices and terms and conditions, at arms' length. As electricity markets are opened to competition, it is essential that the market design encourage forward contracting for most requirements. The establishment of a mandatory (as in California) or quasi-mandatory (as in PJM or New York) power exchange can create market conditions that allow generators to easily exercise market power unless regulatory and antitrust agencies are extremely diligent. There is no precedent in modern times for the necessary level of diligence given the fact that the Sherman and Clayton Acts are generally weak and ill-suited for modern corporate structures, and producers can often exert undue political influence making regulatory remediation equally ineffective. The perceived benefits of mandatory or quasi-mandatory exchanges do not outweigh this risk.

While a root cause of the California crisis was the prohibition on forward contracts, any new long-term contract, while the supply situation remained tight, was not likely to be cheap. In California, a combination of price caps, threatened government takeover, and the uncertainty associated with payments for power sold to a state agency with no prior experience procuring large quantities of power, introduced large risk premiums into the market. The lesson for other states is to never get into that bind in the first place. And the solution is simple. Set up a market design the encourages the use of forward, bilateral contracts, and avoid the temptation to require the establishment of a centralized power exchange with its false promise of "price transparency." Bilateral markets and bidding behavior in short-term markets provide adequate price transparency for markets to efficiently clear without the added risk posed by a centralized exchange.

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[2] Each utility was allowed to procure ancillary services in separate markets operated by the California Independent System Operator or Cal ISO. It was intended that the utilities would procure no more than about 5% of their needs in the ISO markets. Instead, the utilities gamed the two markets and began "leaning" on the ISO's ancillary services market for 20 to 30% of their needs in order to inflate their recovery of stranded costs. See "California Summer 2000 Power Crisis– A Report for ELCON Members," September 2000, at http://www.elcon.org/.

Other states hedged price uncertainty during the transition by requiring owners of divested generation to sell power back to the original owners at cost-based rates under so-called vesting contracts. This was a critical missed opportunity that California could not reverse. Instead, the State's Governor proposed that PG&E and SCE sell the output of their remaining generation (mostly nuclear and hydro) at cost-based rates for up to ten years. The fixed costs of these units had been brought down to "market" via stranded cost recovery. Thus, sales from this capacity at near cost, representing approximately a third of each utility's needs was intended to offset the premiums associated with new long-term contracts.

RECOMMENDATIONS:

- States can reduce the uncertainty in the marketplace—and thus reduce the costs of long-term contracts—by demonstrating that new generation and transmission can be sited and built. This gives the market confidence that new resources will be brought on line in a timely manner, and commitments, during the transition and after, will be honored.
- States should encourage a market design that encourages the use of long-term forward contracts to reduce dependence on more risky day-ahead or day-of purchases.
- States should not encourage or mandate the establishment of any centralized power exchange. But states should not discourage independent, private exchanges from operating in local markets.
- The terms of any vesting contracts resulting from generation divestiture should be limited to a reasonable transition period. Any such contracts should be retired in proportion to the amount of retail load that subscribes to alternative retail providers.
- States should not restrict the willingness of incumbent utilities to divest generation and other potentially competitive business functions.

GAMING BEHAVIOR:
UNDER-SCHEDULED LOAD AND OVERSELLING TRANSMISSION

Gaming can be considered any business behavior that exploits weaknesses or flaws in the market design, and that produce market results that are inconsistent with the objectives of the market design (*e.g.,* efficiency, competition, no undue discrimination, or reliability), while not being in violation of a tariff or market rules. In other words, gaming is behavior that would not have been permitted or possible under a tariff or market rules, had the designers of the tariff or rules anticipated the behavior and were able to preclude it from being exercised in the first place.[3]

UNDER-SCHEDULED LOAD

As soon as the restructured California market began operation in 1998, gaming of market loopholes was evident. Initially, the California market was intended as a transitional market to allow the three major investor-owned utilities to recover 100% of their stranded costs. The mechanism chosen for stranded cost recovery included the establishment of a central "power exchange," a retail rate freeze, and a statutory mandate that the utilities sell all of their generation into the power exchange and buy all their native load or Provider of Last Resort (POLR) requirements (except for ancillary services) from the exchange. The difference between the power exchange clearing price and the frozen retail rate (by rate class) defined the "competitive transition charge" (CTC) paid by ratepayers within a particular retail class to settle the utility's stranded cost obligations.

Each utility was allowed to procure ancillary services (A/S) in a separate market operated by the California Independent System Operator or Cal ISO. It was intended that the utilities would procure no more than about 5% of their needs in the ISO A/S markets. Instead, the utilities gamed the two markets and began "leaning" on the ISO's ancillary services market for 20 to 30% of their needs in order to inflate their recovery of stranded costs. By sharply reducing demand in the power exchange (by under-scheduling each utility's expected load), the power-exchange clearing price was artificially reduced. This increased the spread between the exchange price and the frozen retail rate. But, by excessively leaning on the ISO's A/S markets, the utilities reduced the ISO's margin of error for ensuring the reliable operation of the ISO's control area and the security of the Western Interconnection.

OVERSELLING TRANSMISSION

Transmission customers pay for the service whether it is used or not. Customers pay to *reserve* the service, and should subsequent events or circumstances prevent them from actually scheduling a transaction, or should a transaction be subject to curtailment, they are still obligated to pay the transmission provider. This situation creates a powerful economic incentive for transmission providers to deliberately *oversell* transmission capacity. These transmission providers rely on NERC-certified Security Coordinators to

[3] This definition of "gaming" is adopted, almost verbatim, from: James F. Wilson, "The Regional Transmission Organization's Role in Market Monitoring," Navigant Consulting, Inc., Prepared for the Edison Electric Institute, August 18, 1999.

invoke Transmission Loading Relief (TLR) procedures to curtail enough transactions to prevent all the transactions from going physical.

RECOMMENDATIONS:

- The independent Market Monitoring units or MMUs assigned to each regional transmission organizations (RTOs) should be authorized to search for evidence of gaming behavior in wholesale bulk-power markets, and recommend market design or rule changes to eliminate the behavior.

- When a RTO has implemented any NERC reliability standard or business practice, the "market interface" between such standard or business practice, and the fair and efficient operation of the wholesale bulk-power markets, should be subjected to the same market surveillance standards as other RTO market rules and procedures.

- MMUs should be careful and not identify certain forms of appropriate trading behaviors (*e.g.*, arbitrage) as attempts to unfairly game the market.

GENERATION DIVESTITURE AND VESTING CONTRACTS

One objective of industry restructuring is to force utilities and other suppliers to identify and focus on core competencies. Attempting to retain within a holding company, both regulated and unregulated business functions, requires extraordinary justification under normal best business practices.

As industry restructuring proceeds, utilities are increasingly divesting assets to reposition themselves in a more competitively-driven industry, based on its (and their financial advisors') perception of the prevailing economic incentives. For example, some utilities are exploring the limited spin-off of transmission assets (to form a for-profit RTO or independent transmission company) to take advantage of potentially lucrative performance-based regulatory incentives promised in FERC's Order 2000. But more commonly, utilities are shedding generation assets in order to focus on their "wires" business because the risk of an unregulated generation business is significantly different (and greater) than the regulated T&D business, requiring a different management style and strategy. From a shareholder perspective, these differences are best accommodated in separate corporations.

This reorganization of assets is generally positive and contributes to the unbundling of operating functions and products and services, a necessary pre-condition to a competitive market structure and the mitigation of potential market power. However, real competition will not exist during any state-imposed transition period when stranded cost recovery and other priorities prevent a real market from forming. It is therefore necessary to depart from strict market principles during a transition period to ensure that the interests of customers are protected because the market is not yet able to provide those protections.

In California, generation was divested without vesting the output of those assets with the customers that remained captive to the assets' former owners. To compensate for the error, the State's Governor proposed a requirement that PG&E and SCE be prohibited from divesting their remaining hydroelectric and nuclear generation, and to sell all power from those units to the utilities' customers for ten years at cost-based rates.

RECOMMENDATIONS:

- When rate-based generation is deregulated and divested, the output of those assets should be secured under vesting contracts with the original owner(s) to ensure that any remaining captive customers are served under cost-based rates.
- Vesting contracts between new and original owners of generation should be retired as retail customers begin to switch suppliers, and in proportion to the amount of retail load that is served by new suppliers.
- Any restrictions on the divestiture of generation should be terminated when workably competitive markets have been established.

MARKET SURVEILLANCE

Competitive markets do not exist without rules and oversight by a higher authority. Any transition from a regulated to a deregulated market arguably requires even greater attention to fair play and transparency of market operation under all remaining laws and regulations.[4] The conduct of competition in the U.S. economy is not based on strict laissez-faire principles. All competitive businesses are subject to antitrust and public disclosure laws, including comprehensive market surveillance requirements, intended to protect both investors and consumers from undue predatory behavior.

For example, markets and exchanges for securities and commodities are subject to extensive oversight at all trading levels.[5] In addition, Congress and the states have enacted countless consumer protection laws that target specific abuses. A restructured electric industry—combining both regulated and unregulated market segments—should not be immune from comparable requirements for protecting investors and consumers.

In Order 2000, FERC requires RTOs to perform a "market monitoring" function. Specifically, as Function 6, RTOs are required to: (1) monitor markets for transmission service and the behavior of transmission owners and propose appropriate remedial actions if necessary; (2) monitor ancillary services and bulk-power markets that the RTO operates; (3) periodically assess how behavior in markets operated by others affects RTO operations and RTO operations affect those markets; and (4) provide reports on market power abuses and market design flaws to the Commission and other affected regulatory authorities, including specific recommendations. All FERC-approved ISOs have established a Market Monitoring Unit (or MMU), and all proposed RTOs have committed to the establishment of such an entity.

In addition in the FERC RTO rule, several states have established similar market surveillance functions, typically as separate entities within their regulatory agencies, to study the development of competition in formerly regulated retail markets, and to identify impediments to the full emergence of competition in those markets.

Electricity markets are inherently complex because the physical laws governing the operation of the interconnected grid are not intuitive to most people. This lack of transparency in market operation is especially susceptible to market design flaws, gaming behavior, and market power abuse.

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[4] The need for ongoing market monitoring is minimized if the potential to exercise market power is eliminated in the first place. See ELCON's *Profiles in Electricity Issues: Eliminating Market Power in the Transition to Competition.*

[5] The National Association of Securities Dealers' market surveillance and regulation division, NASD Regulation, oversees trading in approximately 5,000 securities by over 600,000 registered traders.

Three forms of market power abuse are recognized in electricity markets and are subject to federal or state market monitoring functions: (1) vertical power, (2) horizontal power, and (3) localized power. An example of vertical market power would be any market structure, rule, or procedure that allows a transmission owner to give preferential treatment to its unregulated generating or marketing affiliates for access to the transmission system. Horizontal market power would, for example, allow an owner of generation (or group of owners or "cartel") to unduly increase the price of ancillary services or power exchange clearing prices. Localized market power may be exercised by an owner of generation if one or more transmission constraints limit access to the "localized market" by competing generators. A "load pocket" is a prime example of this form of market power.

RECOMMENDATIONS:

THE MARKET SURVEILLANCE FUNCTION

- Any market operated by a RTO, or on behalf of a RTO, should be subject to an independent market surveillance function to monitor such markets for potential design flaws, gaming behavior, and the exercise of vertical, horizontal, or localized market power. This includes markets for transmission services, ancillary services, and power exchanges. This function should not, and need not, extend to the monitoring of power exchanges (and other web-based trading platforms) that are independent of RTOs or bilateral transactions in which the RTO is not a party.

- States are encouraged to establish independent market surveillance functions to ensure that competition in their retail markets is not inhibited by the market design, gaming behavior, or the market power of incumbent utilities and their affiliates.

- The level of market surveillance in wholesale or retail electric markets—where regulated and unregulated entities (and affiliates) are co-mingled in the same market—should be at least as stringent as comparable market surveillance activities in any existing competitive market (*e.g.,* securities) unless the need for less surveillance is otherwise demonstrated.

- When a RTO has implemented any NERC reliability standard or business practice, the "market interface" between such standard or business practice, and the efficient operation of the wholesale bulk-power markets, should be subjected to the same market surveillance standards as other RTO market rules and procedures.

- For RTOs structured as for-profit transmission companies (transcos), all activities or business decisions associated with making tradeoffs between generation and transmission resources (*e.g.,* for the relief of transmission congestion, or generation interconnection policies and procedures), and any transaction involving an affiliate of a passive owner, should be subject to the market surveillance function.

- Uniform standards for market performance should be established and used for the monitoring of markets operated by RTOs or operated in association with RTOs, and for monitoring the "market interface" between NERC reliability standards and business practices, and the wholesale bulk-power markets.

MARKET MONITORING UNITS (MMUS)

- Market monitoring units (MMUs) should be independent of market participants, RTOs, and regulatory commissions. MMUs should recommend to the appropriate regulatory commissions improvements or corrections to market rules and procedures, tariffs, or market design. MMUs may also advise antitrust agencies of any potential antitrust violations revealed by its surveillance activities.
- Each MMU should have adequate resources, professional staff, and the ability to retain outside experts, as it deems necessary, to accomplish its mission. While RTOs are responsible for recovering the costs of market surveillance activities, an MMU's budget should be subject solely to FERC's oversight, and not subject to modification or veto by the RTO.
- MMUs should not be allowed to exercise *de facto* regulatory authorities, *e.g.*, to impose penalties on market participants for improper behavior, to set price or bid caps, or to unilaterally adjust market clearing prices or bids.
- FERC is urged to establish separate MMUs for the Eastern and Western Interconnections with the sole function of ensuring resolution of Function 8 (Interregional Coordination) issues between adjacent RTOs, as they may exist, within each interconnection.
- The professional staff of MMUs should not use their position to advocate a particular market design structure or philosophy for which viable alternative market design structures or philosophies exist.

POWER EXCHANGES AND AUCTIONS

POWER EXCHANGES

California required the creation of a centralized power exchange, the Cal PX, to facilitate the recovery of stranded costs during a four-year transition period. The *Competition Transition Charge (CTC)*, the amount of stranded costs recovered from each ratepayer, was calculated by subtracting the Cal PX clearing price from the applicable retail rate which, under state law, was frozen over the same four-year transition period or until the utility recovered its stranded costs, whichever came first.

The state's three investor-owned utilities were also required to bid all their generation into the Cal PX and to purchase all their requirements (as Providers of Last Resort) from the same exchange (except for ancillary services that were provided by the Cal ISO). The power exchange subsequently became the focal point for several examples of market failure that might have been avoided had no exchange existed in the first place. The Cal PX is no longer operational as a result of FERC actions.

Previously, in England and Wales, government regulators also ordered the abolishment of a central exchange (the "Pool") because problems with horizontal market power of generators proved intractable. As of March 27, 2001, the market in England and Wales is based on bilateral trades. A System Operator procures generation services (equivalent to "ancillary services" in the U.S.) to balance the system loads and generation, manage congestion, and maintain reliability. Settlement is based on generator "incs" ("Offers") and "decs" ("Bids") that are accepted in the near real-time market. Independent power exchanges are expected to provide the main trading platforms for the new market. These exchanges would enable market participants to refine their contract positions close to real time in response to weather and other market variables.

The establishment of a mandatory (as previously in California and the U.K.) or quasi-mandatory (as in PJM or New York) power exchange can create market conditions that allow generators to easily exercise market power unless regulatory and antitrust agencies are extremely diligent in eliminating market power. But there is no precedent in modern times for the necessary level of diligence given the fact that the Sherman and Clayton Acts are generally weak and ill-suited for modern corporate structures, and producers can often exert undue political influence making regulatory remediation equally ineffective. The perceived benefits of mandatory or quasi-mandatory exchanges do not outweigh this risk.

While centralized exchanges pose clear market power risks, independent, private exchanges (typically structured as Web-based auctions/reverse-auctions where buyers and sellers mutually agree on as-bid offers) have an important role in competitive electricity markets. They are strictly voluntary and provide nearly the same negotiating flexibility in short-term markets as long-term bilateral, forward contracts. Independent exchanges are also less likely to be targeted for market power abuse.

AUCTIONS

Any regulatory or statutory requirement to establish a centralized power exchange forces a concomitant decision on the type of auction used for establishing the market-clearing price. This has provoked intense debate between the perceived theoretical merits of the *Uniform-price Auction* (including a variant based on the *Vickrey or Second-price Auction*), and the costly effects of this auction format on any exchange subject to market power. Unless the generation markets are absolutely free of horizontal market power, any auction format that rewards all successful generators the same highest bid (or highest rejected bid) is a windfall to the generators. Except for the generator submitting the winning bid, this auction format provides few economic incentives to the vast majority of the generators that will simply bid "zero" and take the "market-clearing" price. This creates a market that makes it easy for generators to make money, but that is equally costly for consumers.

To prevent such windfall profits, some stakeholder groups and policy makers advocate the *Discriminatory Auction* format in which all winning bids are accepted as bid. While arguments against the use of *Discriminatory Auctions* rely on theoretical conjectures of changes in bidding behavior under different auction formats, it is widely acknowledged that empirical evidence of the superiority of *Uniform-price Auctions* is "inconclusive."[6]

RECOMMENDATIONS:

- Mandatory (or quasi-mandatory) power exchanges are highly susceptible to horizontal market power abuse and this risk is not offset by any compelling benefits that *only* centralized exchanges provide. Competitive markets for electricity should be established without any direct or indirect government mandate for centralized power exchanges. This should not preclude free entry into a market of any independent, private exchanges.
- Any RTO with an approved power exchange (*e.g.*, in LMP-based markets) should reject the use of *Uniform-price Auctions* as the mechanism for establishing a single market-clearing price. The theoretical benefits of this auction format do not outweigh the potential costs associated with horizontal market power in generation markets.
- So-called "hybrid" market structures, with a centralized exchange (*i.e.*, LMP) structure in the near real-time market and bilateral contracts in the forward markets, and which are under consideration by several RTOs, should be tested. Market power problems in the near-term exchange will likely emerge if this market structure is deemed incapable of providing adequate liquidity. This would be an important lesson for going forward.

[6] See, for example, Catherine D. Wolfram, "Electricity Markets: Should the Rest of the World Adopt the UK Reforms?" Program on Workable Energy Regulation (POWER), University of California Energy Insitute, PWP-069, September 1999, page 10.

PRICE CAPS AND "CIRCUIT BREAKERS"

As a general principle, price caps are inconsistent with the basic operation and incentive structure of competitive markets. Where markets are clearly dysfunctional, certain forms of price caps may be necessary to protect consumers and other market participants until the market is reorganized and stabilized. However, once established, price caps are also hard to eliminate. Opposition to price caps often arises over the fear that once price caps are imposed the will become a permanent feature of the market.

One form of price cap that has been used in ISO markets is the bid cap. This sets a limit on the price that a supplier may offer to sell its power.

Price cap proposals generally expand two extremes. At one extreme, the cap would be set as low as possible and approximate cost-based rates. Price caps that are politically motivated tend to be this kind. The other extreme would set the cap rather high and attempt to approximate (and perhaps exceed) long-run replacement costs. This second form of cap is often called a market "circuit breaker" or "damage control" cap.

Price caps are controversial because there is substantial evidence suggesting that they are counter-productive, especially caps that target the low end of the producer-cost spectrum. In California, during the summer of 2000, total costs increased as bid caps were ratcheted down from $750 to, $500, and finally, to $250. Certainly, if caps are set low for long periods of time, they will discourage new investments. And price caps at any level will discourage the entry of price-responsive, curtailable loads into the market and deny the market its rightful "demand curve."

RECOMMENDATIONS:

- As a general principle, price caps (or bid caps) should be avoided because they can severely discourage market entry by price-responsive, curtailable loads and new generation.
- Price caps should not be imposed solely to suppress price volatility. Price volatility is a natural attribute of healthy competitive markets.
- In clearly dysfunctional markets, circuit-breaker type caps may be necessary to prevent a total market collapse. Such caps must be eliminated as soon as the market is functioning properly.
- The bids of price-responsive loads should be exempt from any price or bid caps. Price-responsive load is a *substitute* for any price or bid cap, and any attempt to limit the remuneration to customers reselling their load will distort the market and negate the benefit of a demand response in the market.

Provider of Last Resort (POLR) Service

Provider of Last Resort (POLR) service is usually required in states that have implemented retail choice. It is often called Supplier of Last Resort service. Another variation of this service is Default service. A Provider of Last Resort is that supplier of electricity that is responsible for providing generation service in those instances where a customer is otherwise without service (including for non-payment). More specifically, retail customers who are no longer able to purchase electricity from a retail provider of choice through failure of the retailer or severance of the relationship by the retailer and have not selected a replacement retailer, or who cannot obtain regular electricity services from any retailer, or who choose not to leave their incumbent utility ("choose not to choose"), are eligible for POLR service. Most states require incumbent utilities to be POLRs.

The obligations of the POLR and the customer taking POLR service differ from state to state, but generally the service is structured to resemble traditional bundled service at a fixed, cost-based rate. The service is very similar to the "assigned risk plans" that were used in certain insurance markets (*e.g.*, worker compensation and automobile insurance), and which have since been abandoned in that industry.[7]

As more and more states gain experience with retail choice, some glaring problems have emerged with POLR service.[8] These include: (1) the creation of a market distortion in which customers or marketers can game the POLR service vis-à-vis the wholesale spot markets; (2) suppression of customer awareness of price signals; (3) discourage the market for long-term contracts that would otherwise provide for customer hedging; and (4) prevent incumbent utilities from becoming "wires" companies because they must remain in the business of supply risk management. Each of these problems emerged in California and elsewhere, resulting in either the utilities or its customers being placed in a price squeeze.

Recommendations:

- POLR service should not provide an economic incentive to stay out of the market for any customer that is financially capable of choosing alternative retail suppliers. States should reconsider the consequences of retail rate freezes and the implications of such freezes on market development.
- States that require some form of POLR service, because not all retail customers are eligible or willing to shop at the same time, must ensure that vesting contracts are established between the new owners of generation that was divested by any POLR, and the POLR, to prevent retail customers from being "thrown" into the wholesale spot market.

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[7] Roger D. Colton, "Provider of Last Resort: Lessons from the Insurance Industry," September 1998.

[8] Frank C. Graves and Joseph B. Wharton, "POLR and Progress Towards Retail Competition – 'Can Kindness Kill the Market?'" Presentation Before the NARUC Winter Meetings, The Brattle Group, February 27, 2001.

RELIABILITY OF THE INTERCONNECTED GRID

Reliability (of the electric service) is a much-abused word, meaning different things to different people. Most retail customers associate the word with the availability of power at their low-voltage (distribution) level of consumption. Outages at distribution voltages are relatively common compared with failures at transmission-level voltages because the distribution system is more sensitive to weather extremes, load growth, and utility maintenance practices. But transmission-level outages typically impact a wider geographical area and impose more visible and greater economic costs and risks to public welfare and safety. The legendary Northeast Blackout of 1965 resulted in the creation of the North American Electric Reliability Council (NERC). The 25-hour blackout in New York City in 1977 resulted in widespread rioting, looting, and economic costs estimated in the hundreds of millions of dollars. A series of blackouts in the Western Interconnection in 1998 instigated a major investigation directed by the Secretary of the U.S. Department of Energy. The more recent episodes of controlled "rolling blackouts" in California have been generalized as an "energy crisis" on par with the energy crisis of the 1970s.

NERC Definition of Reliability

NERC defines reliability in terms of two inter-related risks. The first risk is the short-term "security" of the bulk power grid. This means the resilience of the high voltage transmission system to failure if certain inviolate laws of physics are breached. Security addresses the manner in which the interconnected grid is operated, and any failure to operate the grid as prescribed by NERC, puts the grid at risk of an outage. The term "interconnected" connotes the fact that the grid—a single electric circuit—is owned and operated by many utilities, each attempting to operate its own piece of that circuit independent of other utilities.[9] NERC has established a series of nine Operating Policies to maintain security.

The second risk in NERC's definition of reliability is "adequacy." This refers to the availability of generating resources and transmission capacity to meet expected contingencies such as the unexpected outage of a major generating unit or transmission line. NERC has established a series of Planning Standards that are intended to ensure adequacy. Adequate "adequacy" does not always guarantee security. The security of the interconnected grid can be at risk because of the failure to operate the system as required by NERC Operating Policies.

[9] NERC standards generally apply to three separate North American electrical circuits called "Interconnections." These three Interconnections encompass most of Canada, all of the lower 48 states, and parts of Mexico. They are the "Western Interconnection" (west of the Rocky Mountains); the "Eastern Interconnection" (east of the Rockies); and the Electric Reliability Council of Texas (ERCOT) that consists of most, but not all, of the state of Texas.

Since the early 1970s, NERC has been an ad hoc, voluntary association owned by nine or ten Regional Reliability Councils or RRCs.[10] The RRCs fund the activities of NERC. The members of each regional council were typically the utilities that owned the transmission facilities within each region. This included both investor-owned and public utilities. As a strictly voluntary group, without any express federal or state statutory authorization, NERC was and is incapable of enforcing its Operating Policies or Planning Standards. As a result, the actual operating and planning practices of the regional councils and any of its members are not always consistent with NERC standards, or with each other. In the past, when most utilities met the needs of its native-load customers with its own resources, this was not much of a problem except for the many small transmission-dependent public utilities (municipal utilities and rural cooperatives) which had to rely on the willing cooperation of larger transmission-owning utilities to provide wheeling and grid support services to enable the smaller utilities to reliably and economically meet the requirements of their customers. Nonetheless, the volume of such "wholesale" transactions between and among utilities was relatively small compared with the power each utility generated and delivered to its own customers. NERC standards primarily addressed transactions between utilities (or more correctly, between utility "control areas").

Changes in Transmission System Usage

Beginning immediately after enactment of the Energy Policy Act of 1992, the number of wholesale transactions began to grow, especially by third-party users of the transmission system. The 1992 federal law created two new wholesale entities, exempt wholesale generators (EWGs), a new class of independent "merchant" generators, and power marketers. Power marketers are market intermediaries whose core business is to arbitrage interregional cost disparities (and price risks). Power marketers may or may not also own physical generating assets. Their "trading" behavior is quite different from the relatively passive management style of regulated utilities whose core business has traditionally been focused on regulated or political markets, not economic markets.

Many utilities were also becoming increasingly dependent on off-system power purchases because of a *de facto* moratorium on new generation construction. Burned by embarrassing cost overruns associated with investments in nuclear plants, and subjected to regulatory and political pressures to adopt conservation and other social programs as an alternative business model, many utilities abrogated their "public service" or "public interest" responsibilities, and ceased to adequately plan for and make the long-term investments necessary to fulfill those responsibilities. Many utilities established their own power marketing operations to manage increased off-system purchases.

[10] There were originally nine regional councils. A tenth—the Florida Reliability Coordinating Council (FRCC)—was spun off from the Southeast Electric Reliability Council (SERC) in 1996.

The changes in transmission system usage created a dilemma for NERC: the organization's Operating Policies and Planning Standards were rapidly become obsolete. NERC was also under pressure to broaden representation in the organization's governance process to include non-utility stakeholders. The regional councils were also split on how to change the organization and generally resist sharing control with other stakeholders. This split reflects the lack of consensus among utilities on the direction of industry-wide restructuring, and has seriously hamstrung the organization's effectiveness.

The Market Interface

NERC has made one important concession to the changes in electricity markets by creating a new standing committee, the Market Interface Committee (MIC). The MIC's charge is to review the impacts of NERC reliability standards on the commercial electricity markets. Since its inception, the committee has focused its attention on allegations that some transmission providers have been misusing certain reliability standards and practices for commercial advantages. For example, NERC's Transmission Loading Relief (TLR) procedure was intended as an emergency curtailment process that was only used as a "last resort." Instead, the procedure is increasingly invoked as a congestion management tool because transmission paths are regularly oversold. This type of practice jeopardizes the reliability of the bulk-power grid and disrupts the wholesale markets. NERC is incapable of preventing such practices.

RECOMMENDATIONS:

- Congress is urged to enact legislation requiring the establishment of a new North American electric reliability organization subject to FERC oversight. The new organization would have the authority for force compliance with its standards.

- Pending the enactment of federal legislation, NERC should initiate internal reforms of its governance structure that balance the interests of all industry stakeholder groups and eliminate the ability of RRCs or transmission owners, as a group, to veto any NERC action.

RETAIL ACCESS AND MARKETS FOR PRICE-RESPONSIVE LOADS

Every competitive market requires a "demand side" that allows end-use customers to selectively enter the market based on the each customer's individual price responsiveness. This creates the classic downward sloping demand curve that illustrates the theoretical principle that as price increases, quantity consumed (*i.e.*, demand) decreases, all else equal. No customer is ever forced to enter a competitive market in a prescribed manner (*e.g.*, purchase only in a mandatory exchange).

During the mandatory 4-year transition period in California, retail access was deliberately restricted because of the nature of the *Competitive Transition Charge* (CTC), the mechanism used for stranded cost recovery. This discouraged customers from opting for retail choice and demand-responsive load never emerged in the market. In addition, special utility and ISO programs that attempted to encourage demand bids from large customers failed because: (1) the programs were ill-conceived, (2) were deemed punitive by customers, and (2) price caps eventually eliminated any economic incentive to enter this market. Thus, an important resource was artificially kept out of the market at times when it was essential to get every possible resource in play to prevent outages. California and other states are now grappling with how to restructure their markets to incorporate demand responsive loads.

Wholesale-Only Markets

Almost all new competitive electricity markets were structured (by intent or not) as "wholesale only" markets, in which all demand (customer loads) remain aggregated and served on a coincident basis just as it was for almost a hundred years of regulation. Such markets are fraught with risk if generation markets are concentrated and able to exercise market power. This was certainly the situation in California's markets begin in 2000 when demand began to routinely exceed supply.

There is considerable confusion in the public debate on retail restructuring regarding the proper role of retail loads in competitive markets. For example, some advocates recommend that all retail loads, or all large loads, be forced to buy from the wholesale spot markets unless otherwise hedged with "contracts for differences." This, they argue, would ensure demand responsiveness in the market and mitigate price volatility.

But this is *not* real competition. In every other spot commodity market, "retail" consumers are totally absent from the market (except, for example, as investors of futures contracts or speculators). "Demand response" in these markets is provided by wholesale entities (including large manufacturers) or market intermediaries. Only a fraction of total demand may be active in these spot commodity markets, with most purchases from producers locked in forward contracts, but entry is always voluntary and normally limited to players with particular skills in understanding and managing price volatility and risk. Costs in those markets are ultimately reflected in the market prices of finished goods that are purchased by retail consumers, but costs may not be passed through on a dollar-per-dollar basis.

Retail electricity markets should be structured the same way. Purchases from spot electricity markets should be voluntary and by entities with the requisite skills. This does not preclude the price-responsiveness of small retail customers from being used to discipline price volatility, but that will normally be done by aggregation of small residential and commercial loads (with major appliances under real-time controls), and it will be the aggregator that monitors and reacts to real-time prices, not the customers. End-use customers may continue to be billed under an average fixed rate or other commercial arrangements at their discretion. Nonetheless, one or more of their major end-use loads may be bid into short-term markets, and the aggregator compensated at whatever price is negotiated in the market (*e.g.*, in an RTO's ancillary services market).

Markets for Curtailable Load Response (CLR)

Many large industrial consumers with curtailable loads, including many ELCON members, will want to enter the market directly and not via aggregators or other market intermediaries. But it should remain their choice. These customers will typically bid load that is otherwise served under firm long-term contracts or on-site generation, or a combination of the two. The customer may also aggregate curtailable loads from more than one facility in a region, depending on the source of generation that is being resold. ELCON calls the market for curtailable load, "Curtailable Load Response" (CLR) service.[11] Generally, CLR would be bid into regional markets for ancillary services or similar short-term or spot markets. Most industrials will attempt to bid when prices are highest (*e.g.*, day-of or hour-ahead markets) and not in day-ahead markets when the next day's market conditions have to be forecasted.

Many manufacturers have little or no price-responsive load and will not want to enter this market. Their loads will generally be served under long-term firm contracts or on-site generation with special provisions for standby or backup supplies to eliminate the risk of any interruption. It makes no sense to force such customers into the spot market.

RECOMMENDATIONS:

- Markets—not *programs*—for CLR services should be established under the auspices of each FERC-jurisdictional ISO or RTO. This service should be structured as a new Order 2000 Function 9 requirement for RTOs to ensure that markets for CLR services are reasonably standardized within and across Interconnections. CLR services should be structured both as

[11] CLR is a term adopted by ELCON to more accurately describe a service in which end-use customers may bid their loads into short-term markets, and to distinguish such service from demand-side management (DSM) programs to which it bears little resemblance. In some states, CLR-type services are called "load shedding," "negawatts," "demand response," "load management," or "demand relief" programs.

- Markets for CLR should be voluntary. No customer or customer class should be forced to participate in this market.
- The bids of CLR should be exempt from restrictions imposed by any price cap because CLR is a market *substitute* for price caps as a mechanism for restraining price volatility. To the extent CLR bids are subject to artificial price or bid caps, policymakers and regulators should be aware that this will discourage loads from making the investments necessary to participate in CLR markets and delay the emergence of truly competitive markets.
- The opportunity to participate in markets for CLR should not discriminate on the basis of size or the customer's load. All customers and customer classes should be eligible on the same terms and conditions, and compensated at market prices.
- CLR services would not abrogate contracts of existing interruptible customers. Customers with such contracts should be able to participate in CLR markets to the extent that such participation is not precluded under the terms and conditions in the contracts.
- All states should expeditiously establish competitive retail markets that allow end-use customers to choose their suppliers, and to freely negotiate the price, and terms and conditions of service.

RETAIL RATE FREEZES AND RATE CAPS

The stranded cost recovery mechanism adopted in California never anticipated spot market prices (on the Cal PX) exceeding the level of frozen retail rates. In any event, that risk was placed on the utilities. When the demand began to exceed supply on a chronic basis, pushing the PX price above the level of frozen retail rates, the utilities were caught in a dangerous price squeeze.

When SDG&E's rate freeze was lifted, the utility's retail customers were exposed to the price risk of the spot market without any viable options for hedging that risk. The California "crisis" began in June 2000 when high PX and ISO prices were passed through to SDG&E customers and customer bills doubled or tripled.

Rate freezes are common in many states that have restructured their utilities. Utilities and/or customers in those jurisdictions may not be immune from similar price squeezes.

RECOMMENDATIONS:

- Retail customers should not be exposed to wholesale spot market price volatility unless and until the market provides adequate hedging services.
- Policy makers should carefully review the consequences of any rate cap or rate freeze proposal before mandating such action.

STRANDED COST RECOVERY MECHANISMS

The transition to competitive electricity markets might have been easy without the added baggage of stranded cost recovery, but the original problem—substantial utility investments and expenses (capitalized as "regulatory assets") at above-market costs—triggered the need for restructuring in the first place.

Stranded cost recovery defines many of the parameters of the transition period. But, as California has unwittingly demonstrated, an inappropriate stranded cost recovery mechanism can make the transition period inoperable.

Initially, the California market was intended as a transitional market to allow the three major investor-owned utilities to recover 100% of their stranded costs. The mechanism chosen for stranded cost recovery included the establishment of a central "power exchange," a retail rate freeze, and a statutory mandate that the utilities sell all of their generation into the power exchange and buy all their native load or Provider of Last Resort (POLR) requirements (except for ancillary services) from the exchange. The difference between the power exchange clearing price and the frozen retail rate (by rate class) defined the *Competitive Transition Charge (CTC)* paid by ratepayers within a particular retail class to settle the utility's stranded cost obligations. In other words, to earn the right to switch suppliers, the customer had to sharing *all* the net benefits from switching with its previous utility supplier. This recovery mechanism eliminated any economic incentive to switch suppliers during the mandated four-year transition period, except for customers who choose to pay above-market prices for "green" power alternatives.

Stranded cost recovery is a necessary accommodation to advance industry-wide restructuring at a reasonable pace. Few states will have the luxury to restructure its utilities without this accommodation. But it is important that the stranded cost recovery mechanism be as benign as possible to avoid contributing to a market failure.

RECOMMENDATIONS:

- State regulators should be careful in their choice of a stranded cost recovery mechanism to avoid any unintended consequences. The recovery mechanism should not be allowed to directly interfere with market operation, or depend on market operation to determine the amount of a utility's recoverable costs.

TRANSITION PERIOD DESIGN

The transition from a highly regulated industry to a less regulated industry—when tools for market power mitigation are less than perfect—has to be arduous and artificial. The transition period is only a transition, and not a time for either free-market purity or unbending regulatory rigor. As such, expectations during the transition period must be tempered by structural adjustments necessary to allow competition to work, particularly the disposition of stranded costs. Many of the early states, like California, were high-cost states, with huge stranded cost obligations. The final settlement of such costs creates an unavoidable barrier to real competition.

Several attributes of transition period design are necessary. These attributes are: (1) the duration of the transition period; (2) the amount of stranded costs deemed recoverable from ratepayers and the mechanism devised to recover such costs, including requirements that the utility mitigate some portion of these costs; (3) the assignment of responsibility for Provider of Last Resort (POLR) service; (4) treatment of previously rate-based generation that is divested; (5) the need for a retail rate freeze or cap; and (6) the mechanism chosen to expose the generation commodity (and other potentially competitive services) to retail competition.

In 1996, California adopted a relatively short, 4-year transition period to commence in 1998.[12] The original intent was to shorten the transition and accelerate the onset of a "date certain" when real competition would be feasible. This short transition meant that customers would have to pay relatively high ("non-by-passable") stranded cost charges (or "competitive transition charge"). This, coupled with the fact that the CTC was almost defined as the net savings a customer was supposed to receive by switching supplier, killed even the pretense of retail choice in the California market.

Other states, notably Pennsylvania, opted for longer transition periods (typically via settlements with each utility) with a less onerous stranded cost payment requirement during the transition period.

Like the choices for a home mortgage, California opted for a high payment, short mortgage period, while Pennsylvania opted for smaller payments stretched over a longer payment period. This is certainly a legitimate policy choice that states confront. Under the best of circumstances, the transition period will only allow a "constructed" market to operate as each essential feature of competition is gradually established. The so-called "Day One" of competitive markets is, by definition, the last day of the transition period. In California, policy makers and public alike were convinced that Day One was March 31, 1998, and not March 31, 2002.

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[12] While California's restructuring legislation was enacted in 1996, the basic attributes of the transition period (and other pre-conditions to restructuring) were codified in a September 11, 1995 "Memorandum of Understanding" prepared by the Southern California Edison Company (SCE) and supported by many California stakeholder groups.

RECOMMENDATIONS:

- State regulators and policy makers should be candid with the public regarding the existence and limitations of a transition period. The full benefits of competition will only be realized *after* competitive markets are established, not *before* such markets are fully established and mature.
- State regulators should establish independent market monitoring functions within their agencies to monitor the progress of retail competition and to recommend any necessary midcourse corrections to market design, to the stranded cost recovery mechanism, or to other market rules and procedures.
- As part of the transition period design, state regulators should ensure that the following long-term issues are adequately being addressed under state policy to support competitive electricity markets: (1) bilateral, forward markets; (2) fuel diversity; (3) fuel supply; (4) interconnection rights; (5) natural gas infrastructure; (6) new generation; (7) new transmission capacity; and (8) regional transmission organizations (RTOs).