LONG-TERM MEASURES FOR ENSURING COMPETITIVE MARKETS

1. Market Structure: Bilateral Contracts in Forward Markets
2. Interconnection Rights: Removing Entry Barriers to Industrial Cogeneration, Independent Merchant Power Plants, and Distributed Generation
3. Natural Gas Infrastructure
4. New Generation, Fuel Supply, and Fuel Diversity
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Highlights

ELCON's basic philosophy for competitive electricity markets:

- Decentralized market operation that depends on bilateral contracts, and not on mandatory exchanges or centrally dispatched pools.
- Market designs that are resilient to market power problems should be favored.
- Ownership, fuel, size, technology neutral as long as investments are not rate-based
- No undue government interference in market decisions and market operation
- Reforms to existing federal and state environmental and other statutes are necessary so as not to impede the needs of new competitive markets.
- Independent interconnection-wide RTOs should be established to maintain short-term reliability and to promote competitive bulk-power markets.
- The establishment of a new independent reliability standards setting organization subject to FERC oversight. Reliability standards must be clear, transparent, nondiscriminatory, enforceable, and enforced.

MARKET STRUCTURE:

BILATERAL CONTRACTS IN FORWARD MARKETS

Energy Market Structure

In competitive markets for electricity products and services, such products and services should be traded in forward markets through freely negotiated bilateral or multilateral contracts. The market structure should be *decentralized* and allow the formation of regional trading hubs. Independent power exchanges (Web-based trading sites) should be allowed to enter these markets. These exchanges would enable market participants to refine their contract positions as market conditions change (*e.g.,* weather, fuel prices, or economic factors). The exchanges also provide near real-time price transparency by posting energy prices at each trading hub.

Prices in the balancing energy market should be developed within the hour (or less) on a nodal or zonal basis. Prices, in either case, would be known *ex post*.

The near real-time balancing energy and ancillary services (A/S) markets operated by (or for) a RTO should employ a multi-settlement system for the energy transactions in each market. This financially binds energy bids at the market-clearing price in the market in which the bids are made.

The benefits of this energy market structure include:

- **"Look and feel" of other competitive markets** – Decentralized markets is the norm in capitalist societies. There are few examples of centralized exchanges, and fewer optimized "dispatch" markets, in which the entire physical volume of a commodity market is allocated and priced.

- **Product differentiation** – Forward markets allow a variety of contracts, and contract terms and conditions, tailored to the specific needs of individual *customers*. In a market dependent on forward contracting, there is no presumption that all customers want the same physical or financial products, and thus, *the market orientation becomes customer focused and customer driven.* Customers are free to negotiate prices, terms and conditions, risk management, and other services that meet their personal or commercial needs. Suppliers are free to offer innovative and different products and services to individual customers or aggregated customers.

- **Efficient trading continuum** – Bilateral trading is a continuous, dynamic process, unrestrained by the inflexible and programmatic procedural rules of centralized exchanges or centrally dispatched pools that limit trades to preset templates (*e.g.,* day-ahead and day-of or spot transactions). This allows new (and increasingly accurate) information to be rapidly reflected in prices and

the risk management strategies of customers. Real-time forward markets and price information enable end-use customer participation in the balancing energy markets and congestion management. This will greatly enhance short-term reliability and reduce extreme price volatility inherent in supply-side only markets.

- **Innovation** – This market structure—again compared with market designs based on centralized exchanges or centrally dispatched pools—allows free entry of competing market mechanisms (*i.e.,* a "market of markets"), a more customer-driven approach to selling the product (and its complements), and thus, greater opportunities for new technological and market innovations. The emergence of independent web-based B2B platforms for anonymous bid/ask transactions is an example of the potential for innovation in a decentralized market structure.

- **Market power mitigation** – Markets based exclusively on centralized exchanges or centrally dispatched pools, or where an exchange is mandated as part of a hybrid structure (*e.g.,* the Cal PX), are highly susceptible to the horizontal market power of generators. In the United States, policy makers, regulators, and antitrust agencies are not likely to require the degree of corporate restructuring ("unbundling") necessary to adequately mitigate horizontal market power. However, the use of multiple settlements for energy transactions can reduce the amount of gaming and exercise of market power.

Market structures based on centralized exchanges or centrally dispatched pools are carryovers from the "tight" pool and vertically integrated utility structures of the regulated industry where product differentiation, trading flexibility, innovation, and customer responsiveness were generally non-existent.

Transmission Market Structure and Congestion Management

The regulated market for transmission services and RTO responsibilities for congestion management should rely on flow-based, *physical* transmission rights (PTRs) determined in an initial auction. The contract-path model for transmission services embedded in FERC rules and regulations should be abandoned.[1]

PTRs should be limited to *flowgates* as determined by a RTO or NERC. Flowgates are defined as transmission interfaces that experience commercially significant congestion, and therefore, require financial settlement. The transfer capability of a flowgate is based on the simultaneously feasible thermal/stability limits of other flowgates involved in any transaction as allocated by *power transfer distribution factors (PTDFs)*. PTDFs are calculated by NERC's *Interchange Distribution Calculator (IDC)* and are used by NERC-certified Security Coordinators to invoke Transmission Loading Relief (TLR) Procedures.

[1] The contract-path method ignores the consequences of loop flows or parallel path flows (*i.e.,* Kirchoff's laws) in any transmission transaction.

PTDFs are calculated based on all system impedances and the addition of a new flowgate will not change the PTDFs across existing flowgates. The removal of flowgate status on an interface should typically follow the addition of new generation or transmission capacity and the market for PTRs on the interface should have adequate time to adjust.

The benefits of this transmission market structure include:

- **Tradability of transmission rights in secondary markets** – PTRs are fully tradable, and this enables transmission congestion to be "self-managed" in forward markets. Unlike *financial* transmission rights (FTRs), which have limited liquidity in secondary markets, efficient secondary markets for PTRs can be established.

- **Lower transaction costs** – Participation in forward markets, and one or more independent power exchanges, will be familiar to large customers with experience in competitive natural gas markets. With PTRs, bilateral trades are achievable without a "middle-man."

- **Market Power Mitigation** – The establishment of secondary markets for transmission capacity are an important form of market power mitigation.

RECOMMENDATIONS:

- **Market structure** – The market structure should be decentralized and allow the formation of regional trading hubs. Most electricity products and services should be traded in forward markets through freely negotiated bilateral contracts.

- **Locational pricing to clear real-time markets** – Spot prices in the balancing market should be developed as close to real-time as practicable and on a nodal or zonal basis.

- **Flow-based, physical transmission rights** – The regulated market for transmission services and RTO responsibilities for congestion management should rely on flow-based, physical transmission rights. The contract-path model for transmission services embedded in FERC rules and regulations should be abandoned.

- **Secondary markets for physical transmission rights** – Secondary markets for physical transmission rights should be established.

INTERCONNECTION RIGHTS:

REMOVING ENTRY BARRIERS TO INDUSTRIAL COGENERATION, INDEPENDENT MERCHANT POWER PLANTS, AND DISTRIBUTED GENERATION

The widespread development of innovative and independently owned generation resources in a competitive electricity marketplace is one of the great promises of industry restructuring. These resources include industrial cogeneration and self-generation, merchant power plants, and distributed generation (DG).[2] Each of these technologies, which are financed in private capital markets, provides entrepreneurial and operating efficiencies and environmental benefits that have been absent from past *rate-based* utility investments. The proximity to customer load of some of these technologies (*e.g.,* DG and industrial cogeneration) also provides other benefits, including enhanced power quality, short-term reliability, and deferment of investments in new or upgraded transmission and distribution facilities. However, that does not diminish the value of relatively large merchant power plants provided that they are sited to efficiently mitigate transmission congestion.

But utilities have always fiercely opposed technological competition, *i.e.,* any attempt by retail customers or other entities to bypass the utility's "one-size-fits-all" service with a superior inside or outside the "fence" alternative. As a monopoly, a utility has no economic incentive to conduct interconnection studies and negotiate interconnection agreements with new independent generators (of any size) on a *best business practices* basis. Quite to the contrary, utilities routinely use their monopoly advantages to harass any potential competitor and manipulating the process for obtaining and constructing physical interconnection with a utility's transmission or distribution network has always been one of the more repressible means for discriminating against independent generators.[3]

Industry restructuring does not end this problem. The continuation of utility holding companies in an era of supposed "competition" perpetuates the coexistence of regulated and unregulated affiliates within the same corporate entity. The business mindset of these entities also tends to replicate traditional utility (*i.e.,* monopoly) values and aspirations and not the free enterprise motivation of truly competitive industries. The utility holding company restructure in a partially deregulated environment creates the economic incentive to use control of regulated services to give preferential treatment to the business transactions of unregulated affiliates. Thus, any potential competition to a utility's generation or power marketing affiliates can be impeded by all sorts of arbitrary

[2] Distributed Generation (DG) is generally recognized as a subset of a class of capacity or energy resources called "Distributed Resources" or "DR." However, there is no general agreement on what qualifies as a "DR" or "DG." Some advocates would limit DR to small-scaled resources with a name-plate rating at or below some arbitrary threshold regardless of the economic and/or environmental benefits of larger units.

[3] **[Cite ELCON/API successes in the 1980s defeating challenges to PURPA by EEI and AEP]**

"entry barriers" imposed by sister transmission or distribution affiliates. The Electric Power Supply Association (EPSA) aptly illustrates this problem:

> In short, entities that may be economically advantaged by delaying new interconnections, that may be inclined to favor transmission solutions over generation solutions, and that stand to gain from having transmission upgrades paid for by generators should not be charged with determining the nature and scope of a new generator's interconnection.[4]

EPSA also correctly alludes to a new entity in the restructured industry with similar prejudices. FERC Order 2000 allows the establishment of for-profit transmission companies that may qualify as RTOs. Whether such entities can be created that are truly independent of ostensibly *passive* utility owners is one issue; but an equal concern is the economic incentive "to favor transmission solutions over generation solution." Transmission and generation often compete to relieve transmission congestion. Given the fact that FERC continues to regulate transmission—and has offered the promise of financial incentives to increase transmission investment—the economic incentive to discourage new generation that might also relieve transmission congestion becomes compelling.

RECOMMENDATIONS:

Basic Right to Interconnect with the T&D Network

- **Nondiscriminatory interconnection service** – Access to interconnection service should not discriminate on the basis of ownership, technology, fuel, QF-status, or size. New small facilities should not be given superior rights compared with large facilities simply because they are small, and vice versa.

- **Standby, maintenance, and supplemental services** – Interconnection with the T&D network of any utilities should not in any way impede the ability of a new generator to access fair and nondiscriminatory standby, maintenance, and supplemental services.

Industrial Cogeneration and Independent Merchant Power Plants

- **RTO administration of interconnection service** – Any new generator that seeks interconnection to the bulk-power transmission system should have the right to request interconnection service pursuant to a FERC-approved nondiscriminatory interconnection service administered by an RTO. Such services, including a *Model Interconnection Agreement*, should be specified and enforceable in RTO tariffs. The model agreement should establish a framework for negotiations, and if necessary, serve as a default agreement in the absence of a mutually negotiated bilateral agreement.

[4] Electric Power Supply Association, "EPSA Position Statement on Bill of Rights for New Generation Interconnection," June 2000. ELCON's recommendations on interconnection adopt many of the EPSA positions.

- **Interconnection studies** – A new generator should have the right to an interconnection study performed by an independent (not-for-profit) RTO or other qualified independent contractor certified by the RTO. For interconnections to facilities operated by for-profit RTOs (*i.e.,* Transcos), the new generator should have the right to have any interconnection study performed by the RTO audited by an independent contractor, or alternatively, the right to have such studies performed by an independent contractor. A new generator should have the right to participate in the interconnection study process and to have the study and the interconnection completed in an expeditious manner. At the discretion of the new generator, the negotiation of the interconnection agreement may proceed in parallel with the interconnection study.

- **Queuing policy** – FERC should promulgate a fair and nondiscriminatory policy or rule for guiding the processing of multiple applications for interconnections. A new generator should have the right to no inferior standing in a "queue" compared with any existing generator that is seeking to expand its generating capability at one or more sites.

- **Interconnection agreement** – A new generator should have the right to execute a FERC-approved interconnection agreement that specifies exactly what is necessary for the project to safely and reliably interconnect with the bulk-power system.

- **Interconnection costs** – A new generator should have the right to receive a binding commitment as to all interconnection costs and the right to own certain of the interconnection facilities. Interconnection costs that benefit other market participants, in addition to the new generator, should be allocated to the other market participants in proportion to benefits received (See below, "Transmission system enhancements").

- **Interconnection construction schedule** – A new generator should have a right to receive a binding commitment as to the construction schedule with rights to liquidated damages if the interconnection service provider fails to perform on schedule.

- **Transmission service reservation** – Any new generator should not be required to reserve transmission service as a pre-condition to the physical interconnection to the grid. Generation owners are not always the party responsible for ultimately identifying points of delivery.

- **Transmission system enhancements** – If a new generator is required to financially support an upgrade to the transmission system or enhancement of the system beyond what is required under a minimum interconnection standard, the generator should have the right to receive transmission rights

and/or congestion revenues in proportion to the amount of capacity created by the upgrade or enhancement.

Distributed Generation

- **Nondiscriminatory interconnection service** – Any new distributed generator that seeks interconnection to a utility's distribution system should have the right to request interconnection service pursuant to a state-approved nondiscriminatory interconnection service. This service should include a Standardized Interconnection Agreement.

- **National Interconnection Standards** – The development of uniform standards for interconnecting distributed resources with electric power systems by the Institute of Electrical and Electronic Engineers (IEEE) eliminates important economic and technological barriers to market entry by small-scale distributed generators.

- **Stranded T&D costs** – Utility transmission and distribution companies should not be financially immunized from any risk associated with customer loads, and therefore are not entitled to stranded cost recovery for any activity that is exclusively on the customer side of the meter. It is illogical—and perhaps self-serving—that utilities would claim exposure to such risks (in the same context as the "stranding" of generation assets) and at the same time seek financial incentives to construct new or upgraded facilities because of past under investment in the same T&D assets.

- **Prohibition on distribution company ownership of DG** – Regulated distribution companies should not be allowed to own and rate-base distributed generation assets. Otherwise, this would allow the local utility to return to the generation business. "Wires" companies need to establish a business culture, and business values, that are compatible with deregulated generation markets and competitive markets in general.

NATURAL GAS INFRASTRUCTURE

Most new generating capacity that is planned or under construction is expected to burn natural gas. For example, the Energy Information Administration estimates that 93% of planned capacity additions through 2004 will be gas fired. Natural gas enjoys this advantage because of an unusually sustained period of relatively low wellhead prices (the infamous "gas bubble") and aggressive marketing of the environmental benefits of natural gas compared to coal, hydro, or nuclear. But low wellhead prices also discouraged domestic exploration for new reserves and development (new drilling) of existing reserves, and hence, the emergence of a classic "boom/bust" cycle of prices.

The fact that recent price increases in domestic natural gas markets have coincided with electric capacity shortages in some regions has raised fears that a competitive electric industry may become too dependent on natural gas as a fuel. For example, in California, the state's power crisis coincided with extraordinary increases in wholesale natural gas prices. The price of natural gas crossing the border into California from Arizona was often double the national average.

Traditional Service to Core and Non-core Customers

Traditionally, backbone transmission pipelines deliver baseload gas supplies, including storage injection. Any slack capacity is compressed (or sometimes, liquefied) and stored for peak supplies. This allows gas-on-gas price competition in forward and spot markets for this commodity. Storage strategies were developed primarily to meet the peak needs of core markets such as residential and commercial space heating in the winter months. Industrial process consumers and power generators are generally classified as non-core customers, and served as interruptible loads in the event core customers need the capacity or commodity.

New Convergence Issues

However, non-core customers are almost always connected to the electric transmission system that also serves the compressor stations of the pipelines. This poses no risk as long as non-core consumption is a small fraction of core consumption. But for many LDCs, non-core consumption by industrial process consumers and power generators has become the dominant on-system load, and demand by power generators in peaking periods for electricity reduces "slack" capacity available for gas storage in the off-peak periods of the gas market. This imposes new stresses on the natural gas infrastructure in the gas market's traditional peaking and off-peak seasons that can only be eliminated with the construction of new infrastructure.

RECOMMENDATIONS:

- **Convergence** -- Electricity and natural gas markets are becoming increasingly intertwined (*i.e.,* convergent), and the planning and siting of additions to the natural gas infrastructure should reflect this change.

- **Need for new interstate pipelines** – The rapidly increasing demand of non-core natural gas customers, associated with both industrial processes and power generation, requires new interstate pipeline capacity to meet not only these needs, but to restore slack capacity necessary to support the storage requirements of traditional core customers that is otherwise displaced by the generators' peaking requirements. Market commitments for new pipeline expansions should accommodate this dichotomy of needs.

- **State responsibilities** -- New storage facilities and intrastate pipelines should be designed, sited, and built to meet the market-driven needs of power generators, by recognizing the unique characteristics of the electricity markets and, as a result, the more diverse seasonal demand of the natural gas markets. This may require the rationalization, or redefinition, of core and non-core customers with the realities of mutually competitive electricity and gas markets.

- **Approval process** – The regulatory approval process for new storage facilities and pipelines should be streamlined, and approvals should be forthcoming on a more timely basis.

- **Premium fuel/storage competition** – The need for new storage and pipeline capacity should always be balanced against the market's ability to provide peak-shaving supplies from CNG or LNG.

NEW GENERATION, FUEL SUPPLY, AND FUEL DIVERSITY

Generation "Planning" Under Regulation

A major motive for industry-wide restructuring was—and remains—the perception that electric utilities poorly planned for, and later mismanaged, their huge investment in nuclear generating capacity. Beginning in the late 1950s, and ending no later than the Three Mile Island incident in 1978, "nuclear" was the fuel of choice and even relatively small capitalized utilities attempted to undertake the responsibility for developing one or more of these costly assets. Several such episodes, involving the Western Public Power Supply System ("WPPSS," or more popularly remembered as "WHOOPS"), Public Service Company of New Hampshire (PSNH), and the El Paso Electric Company, resulted in bankruptcies. The largest share of the stranded costs—that have become a down payment for change—are associated with the above-market fixed and variable costs of nuclear plants, and the closing of the books on this unfortunate legacy.

But high-cost nuclear plants were not the only problem. Other power generating technologies also contributed to the stranded cost problem, albeit for different reasons. PURPA-qualifying generators were an issue because some state energy policies failed to implement the federal law as intended. The intent was to hold retail customers harmless to the displacement of utility generation by more efficient on-site customer generation. Instead, state implementation rules allowed "avoided costs" set at levels that greatly exceeded a utility's actual costs. The avoided costs were typically guaranteed in "standard offer" contracts. The above-market valuation of these contracts became another component of the down payment for change.

Utilities were also under pressure from regulators and environmentalists to increase investments in renewable energy and "demand-side" resources, often as politically motivated retribution for emerging problems associated with nuclear plant financing and construction. The regulatory and siting process in many states was increasingly subject to "capture" by environmental interests.

This is all history. But the legacy of this experience—other than the *Competitive Transition Charge* now paid by at least half the nation's electricity consumers—was a virtual nation-wide moratorium on the construction of new generation by utilities. For example, California maintained a de facto "no build" policy for at least a decade because it believed that conservation could meet all the needs of new demand growth. The slow economic growth of the 1980s, also reflected in lower forecasts of electric demand growth, became the excepted industry norm. The unexpected and sustained economic (and power demand) growth of the 1990s caught many utilities and their regulators sleeping at the wheel. As one state after another enacted legislation to deregulate power generation, a new risk emerged.

New Generation: The Current Predicament

Several regions of the country face shortages of electric generating capacity. There is also growing concern that planned capacity additions may be too dependent on natural gas as the primary fuel. As wholesale and retail power markets become more competitive, any "shortage" becomes a potentially huge political issue because market forces will always force prices to what the market will bear, and flawed market structures can compound such costs. Under traditional regulation, utilities had an inherent incentive (or obligation) to overbuild, and actual power shortages (*i.e.,* failure to serve end-use customers) were invariably associated with major transmission or distribution outages. The rolling blackouts in California were a rude departure from this tradition.

Several regional electricity markets in the United States inherited relative "tight" capacity reserves. Some, like Texas and the Midwest, have made great strives to upgrade the generation resource base necessary to support a competitive market. Others, like the West and Northeast, are still behind.

Barriers to New Generation

The traditional barriers to the construction of powerplants continue in a competitive industry. These include delays in the siting and permitting of new plants, environmental restrictions on fuel choice, land management and water use issues, and increased local opposition to the mere presence of a power plant regardless of the need. In addition, the siting and permitting processes for a new generating plant are exposed to significant delays and other uncertainties if natural gas pipeline and/or transmission capacity constraints also have to be addressed as a pre-condition to the construction and operation of the powerplant.

New barriers include price caps and certain so-called *advantages of incumbency*: (1) discriminatory interconnection policies of transmission utilities with generation affiliates, and (2) subsidization of the fixed costs of existing generators resulting from stranded cost recovery. Barriers associated with price caps and the physical interconnection are serious problems in many regions and have been addressed elsewhere in this paper.

Fuel Diversity

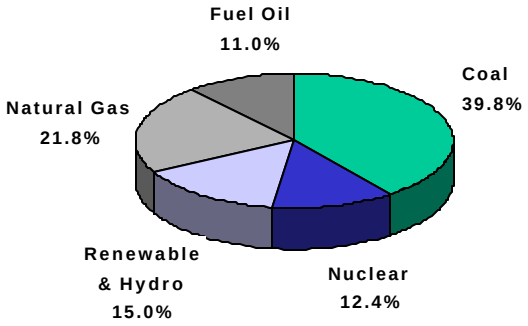
Fuel diversity is protection, as perceived by regulatory bodies or the market, from uncertainties associated with fuel availability, price, reliability of delivery, and regulatory changes. But the developer's choice of a particular fuel to fire a new generating asset is intertwined with the per-kilowatt cost of the generator technology, the expected performance of the technology during its depreciable life, and his or her assessment of the expected risks associated with the fuel, such as availability, price, reliability of delivery, and regulatory changes. This is a

complex matrix of economic decisions and tradeoffs that is ideally suited for markets. One definition of competitive markets might be “the open process that best reconciles price, technological, and regulatory risks."

The introduction of competition in the electric industry has already substantially improved the fuel diversity or “generation mix” of the industry. In the totally regulated (“utility”) generation sector, coal and nuclear are the primary fuels accounting for 78% of generation (in kWh). The fast-growing unregulated (“non-utility”) generation sector relies on natural gas for over 50% of its generation. Combined, the market shares of each fuel are becoming more evenly spread with coal maintaining the largest share. But these figures reflect national averages. The market shares are different depending upon local access to fuels and environmental restrictions. For example, hydro is prevalent in the Pacific Northwest, natural gas in the Southwest, and coal in the Midwest.

Installed U.S. Generation by Fuel Type

(Source: U.S. DOE, 1999, Summer Capability)



More recently, the debate on “fuel diversity” is directed at the perception that natural gas is the “fuel of choice.” Proponents of coal, nuclear, and renewable resources all have their marketing campaigns directed at promoting greater interest in their resources. Certainly, the fact that 93% of planned capacity additions through 2004 will be gas-fired is attributable to the low prices of this fuel in recent years and perhaps a flawed conventional wisdom that “2 dollar” gas would last forever. This does not mean that natural gas is currently over used, or that market corrections will not be forthcoming as relative prices with competing fuel change.

Ideally, competitive markets should dictate fuel diversity provided there are no market distortions that inhibit the markets from efficient choices. The most critical “distortions” are public policies or regulations that needlessly interfere with market choices. These include policies that artificially handicap the choice of coal or nuclear because of unfounded or exaggerated environmental liabilities.

RECOMMENDATIONS:

- **Environmental compliance** – Market forces should be allowed to dictate fuel and technology choice decisions subject to applicable Federal and state environmental laws. Federal and state air and water permitting laws should be reformed so as not to impede the needs of new competitive markets. Guidelines and rules for environmental compliance should be fuel and technology neutral and not attempt to *legislate* policy outcomes that the U.S. Congress, or the relevant state legislature, has not explicitly authorized.

- **Siting and local permitting** – The siting and local permitting procedures for new powerplants should be streamlined and reformed to address the needs of a competitive electricity and natural gas industries. Federal, state, or local siting and permitting regulations should not be used to perpetuate *central planning* approaches (*e.g.,* IRP) to resource decision-making. "One-stop-shopping" permitting processes should operate in fact, as well as, in name.

- **Accountability of regulatory agencies** – Regulatory agencies authorized to administer and enforce air and water quality, land use, or other statutory limitations on the development of new electric generation have a burden to help minimize the compliance costs of applicants and regulatory uncertainties, and to timely execute their responsibilities. The mission of environmental agencies should emphasize solutions (*i.e.,* reconciling conflicting public policy objectives with the application at hand) and not to advocate a particular position on energy policy.

- **Federal funding of energy R&D** – Federal support for the research and development of new energy production technologies should be fuel and technology neutral and not attempt to second-guess choices subsequently made in the marketplace. Federal funding should always require co-funding from industry sectors that may benefit from taxpayer support.

- **Tax credits, subsidies, and portfolio standards** – Federal and state policies to promote the development of new power production investments and associated infrastructure should be fuel and technology neutral and not attempt to "pick the winners."

- **Price caps** – Any price cap set at or below the level necessary to attract new generation will discourage such investments. Price caps in the form of "circuit breakers" are only justified to prevent market collapse.

- **Fuel supply** – Access to federally-owned public lands should be liberalized to the extent necessary to ensure adequate exploration and extraction of primary fuels such as oil, natural gas, and coal, and for the development of non-traditional resources such as geothermal, wind, and solar.

- **Fuel diversity** – An essential federal policy necessary to ensure fuel diversity in the generation of electricity is nondiscriminatory access to transmission service, and the requirement that all users of the transmission system be subject to the same rates, and terms and condition of service. Fuel diversity is harder to maintain in smaller regional markets, where a one or more fuel resources provide disproportionate local economic benefits in the form of jobs and taxes. Existing FERC policies and regulations discourage the free movement of power within an Interconnection that would promote more fuel-on-fuel competition.

- **Cogeneration** – The cogeneration of steam and electricity in industrial and commercial applications should be encouraged by the removal of all impediments to the development, construction, and interconnection of such assets. This technology is arguably the efficient and beneficial, in terms of its impact on the economy and the environment.

- **Nuclear power** – The merits of nuclear power as a viable generating resource deserve reconsideration in the new competitive industry. But any new proposed nuclear plant must be funded in private capital markets and not rate-based.

- **Coal** – Private and government funding of advanced clean coal technologies (CCT) should be encouraged to leverage the fact that coal remains the country's most abundant and secure energy resource.

- **Renewable resources** – No fuel or technology should enjoy a guaranteed market share which is the intended purpose of so-called "portfolio standards" for renewable energy resources. The market for some of these resources should thrive in a competitive marketplace because retail choice will enable customers to bypass traditional one-size-fit-all utility service.

NEED FOR NEW TRANSMISSION CAPACITY

One unexpected benefit of the California crisis has been the heightened awareness by that state's press, policy makers, and general public on the importance of transmission capacity for ensuring reliable electricity supply and preventing rolling blackouts. "Path 15" in the state's Central Valley received front-page exposure in all of the state's major newspapers, and this generated widespread political support for upgrading the transfer capability of this critical transmission interface.[5] But other transmission "paths" vital to California's economy were also habitually constrained.

Prudent transmission planning should not have to rely on a "crisis" environment to resolve issues associated with the need for and siting of new or upgraded transmission facilities. The inadequate transmission infrastructure in California was not an unintended consequence of deregulation but the result of the state's prior reliance on the regulatory paradigm most widely known as *Integrated Resource Planning* (IRP). Ongoing problems with the transmission infrastructure are the result of years of neglect. Transmission was the regulated industry's stepchild, and rarely got the attention that utilities gave to generating assets, or that some regulators conferred on DSM and renewable resources.

NERC's Transmission Adequacy Issues Task Force

The North American Electric Reliability Council (NERC) established the Transmission Adequacy Issues Task Force to identify issues and recommendations pertaining to transmission facility adequacy. The task force's preliminary issues and recommendations are grouped in five key areas: (1) transmission planning, (2) cost recovery, (3) transmission siting, (4) education, and (5) coordination. The task force admitted that each of these issues was "not necessarily new" but that the "changing industry structure provides for a new or different perspective on these issues."[6]

The NERC task force said that most current transmission projects are driven by localized or regional reliability needs or requirements to connect new independent generators to the bulk-power grid. In part, this results from "the growing tendency to over emphasize the business case for major transmission projects and place less weight on reliability." The transactions in the bulk power markets are overwhelmingly short term in nature, with few commitments for long-

[5] In January and February 2001, rolling blackouts in the northern part of the state were called by the Cal ISO because this facility was constrained and unable to deliver available generation from Arizona and elsewhere. In previous years, northern California relied on excess generation from the Pacific Northwest to meet its winter peaking needs.

[6] North American Electric Reliability Council, "Preliminary Issues and Recommendations Pertaining to Transmission Facilities," Report to the Planning Committee, Prepared by the Transmission Adequacy Issues Task Force, March 7, 2001. ELCON's recommendations adopt some of the task force's recommendations.

term transmission service. Not stated in the task force report is the fact that cost recovery for IPP-driven requests is usually the responsibility of the generator. Investments of the long-term needs of the market, or for reliability, run into the problem of retail rate freezes or caps, and jurisdictional uncertainties.

The NERC task force identified several other planning issues. Transmission margins had become so "thin" that construction outages required to complete some new projects were becoming difficult or impossible to schedule. Requests for interconnection and transmission service was "overwhelming the available manpower resources throughout the industry." Finally, the analytical tools and the expertise to apply the tools were not keeping up with market needs.

2. Cost Recovery

The NERC task force repeated the often-stated utility concern "about the recovery of transmission investment at a fair rate of return." It also identified the risk of "regulatory disallowances" and unclear responsibilities for ultimate payment for transmission additions and upgrades as other disincentives to new construction. The task force report did not discuss the roles played by retail rate freezes, or rate caps, and the refunctionalization of transmission assets in response to RTO formation, on cost recovery. Both actions were often advocated by the utilities.

3. Transmission Siting

The NERC task identified siting issues as "significant obstacles" to the construction of new transmission facilities. This includes the difficulties associated with acquiring regulatory approval and the right-of-way for transmission lines. Right-of-way is often strongly opposed by landowners and public interest groups. The report also identified the:

> … failure of the project sponsors to clearly define the need and justification of transmission to the regulatory and public entities leads to controversial situations. These issues become even more imposing to address when transmission lines cross over state or international boundaries, where several regulatory bodies, each with different perceptions of the project need and usefulness, are involved.

4. Education

The NERC task force spreads the blame for "lack of understanding" or "expertise" involving transmission projects across the entire spectrum of industry participants—"from the planners to the users." It singled out investment bankers in particular for failing to appreciate the viability of new projects. The report stated that local, state, and Canadian provincial regulatory agencies lacked engineering expertise and did not have adequate knowledge of deregulation and FERC orders and their impacts on transmission. The task force faulted the transmission providers themselves for inadequately educating the public,

regulators, and administrative law judges (ALJs) "on the complexities, constraints, and consequences associated with transmission and generation adequacy, power system expansion, electricity market structure, and new and expanding market forces."

5. Coordination

Coordination—a uniquely NERC word because the organization has no statutory authority to enforce compliance with its reliability standards—involves the negotiated adoption of, and compliance with, often obtuse engineering specifications associated with maintaining the electrical integrity of a huge electrical circuit (an Interconnection) with multiple owners and operators. Using an automobile as an analogy, ten people attempting to steer a single vehicle at the same time must "coordinate" their activities to prevent the vehicle from crashing.

To coordinate efforts to ensure greater transmission adequacy, the NERC task force believes that "a wide range" of stakeholder interests should be involved in the planning process. But issues that will be especially difficult to coordinate are: (1) the need to plan outages to accommodate new transmission reinforcements; (2) "seams" problems at the boundaries between transmission systems and RTOs; (3) differences among the requirements of neighboring states (and Canadian provincial bodies); and (4) the uncertainties with respect to evolving RTO structures and participants.

Incentives for New or Upgraded Transmission Facilities

The NERC task force did not explicitly address the issue of financial incentives or performance-based regulation (PBR) to encourage the development of new or upgraded transmission facilities. In its defense, NERC or any of its committees, subcommittees, or task forces cannot advocate (or oppose) any policy that would take money out of one NERC participant's hand and give it to another participant.

Any incentive given to a monopoly supplier is a non sequitur. A monopolist's status as the only game in town gives it a unique advantage when offered an incentive to induce some desired behavior, it can simply hold out for a better offer. Incentives are only sustainable in competitive markets where more than one supplier is eligible to respond to the incentive. Some regulators may argue that their oversight role can substitute for this market discipline by the threat of explicit penalties for any failure to meet targeted performance improvements. This may be true for a couple of years, but regulated utilities outlive the typical regulatory commissioner by many years (or generations). Regulation is inherently a political process and not a viable surrogate for a competitive market. Regulatory agencies should accept the limitations of imperfect regulation, and work within the *second-best* confines of cost-of-service principles.

RECOMMENDATIONS:

- **Obligation to serve** – The Federal Energy Regulatory Commission (FERC) should establish a binding *obligation to serve* for its jurisdictional transmission providers to ensure that new additions and upgrades to the interstate transmission system are prudently planned for, and developed, to maintain short and long-term reliability.

- **Mandatory planning margin** – Major transmission projects should be developed with sufficient margin to provide capacity beyond the current three to five year planning horizon and to conserve valuable right-of-way corridors. Such margins should include the use of larger conductors, double circuit lines, and designs for higher voltage operation.

- **Role of RTOs** – As required under FERC Order 2000, RTOs should play a major role in the planning of new and upgraded transmission facilities. In many respects, RTOs will replace the traditional utility role. However, RTOs are still under development and this will unavoidably delay ongoing planning initiatives.

- **Free entry to transmission construction** – Enactment of the Public Utility Regulatory Policies Act (PURPA) in 1978, and Title III of the Energy Policy Act of 1992, demonstrated that unregulated generators (*i.e.,* generators exempt from traditional regulation under federal and state laws) provided an economically viable alternative to rate-based utility generation. The same concept should be tested with transmission assets. However, certain pre-conditions may be necessary to fairly validate this concept, for example, competitive bidding and the existence of a robust secondary market for physical transmission rights.

- **Level playing field** – All users of an interconnected transmission system should be subject to the same rates, and terms and conditions, for service.

- **Cost recovery of projects needed for reliability** – Regulated transmission providers are entitled to a reasonable opportunity to recover alls cost associated with its prudently incurred investments, plus a return on such investments, as long as such assets are deemed used and useful. In the past, this time-honored principle of *cost-of-service* regulation afforded the common stocks of utilities the same investment status as bonds, which did not prevent the financing of the existing transmission infrastructure.

- **Cost recovery of projects needed to expand transfer capability** – Any market participants should be allowed to invest in transmission upgrades that increase transfer capability and retain the transmission rights and/or congestion revenues in proportion to the amount of capacity created by their investment. Any transmission rights may be released into the secondary

markets. Such projects should rely on private capital and should not be rate-based. It is appropriate for FERC to treat such projects with light-handed regulation and not subject such facilities to prudence reviews. The project owners and investors may also negotiate with the developer some form of performance contract with milestones and incentives (rewards and penalties).

- **Federal siting authority** – Congress should delegate to FERC the same authorities under the Federal Power Act with respect to the siting of interstate transmission facilities as FERC is currently authorized under the Natural Gas Act with respect to the siting of interstate natural gas pipeline facilities.

REGIONAL TRANSMISSION ORGANIZATIONS (RTO)

A competitive electric industry requires independent system operators for the same reason independent air traffic controllers exist in the airline industry. Any commercial conflict of interest can compromise safety and reliability as well as create an unfair competitive advantage. Pursuant to FERC Order 2000, Regional Transmission Organizations or RTOs are under development in most parts of the country. It is an open question whether any of these entities are suitable end-state structures for the new industry. Many are too small and incompatible with existing market trading patterns, or fail to meet any reasonable definition of independence.[7]

The power crisis in California is noteworthy in that a FERC-approved ISO was a major player in the ongoing crisis. This created an unexpected opportunity to test the merits of the ISO's operational control. The Cal ISO had many features of a RTO, and certain features that were missing, have since been added. In a crisis with no end of bad news, the Cal ISO's performance during the emergency was been notably positive.

The crisis provided the following lessons associated with RTO formation:

- **Independence** – As soon as the crisis began in mid-2000, the merits of the Cal ISO's stakeholder board were called into question. In the emergency, the stakeholder board was paralyzed by conflicts of interest. Under FERC order, an independent board was established.

- **Operational Authority & Short-term Reliability** – The Cal ISO managed to "keep the lights on" for three large utility systems for 32 consecutive days of Stage 3 emergencies when reserves were less than 1.5%. It is inconceivable that the three large California utilities, acting in their own selfish interests, could have done the same.

- **Tariff Administration & Design; OASIS & Calculation of TTC and ATC** – The Cal ISO performs these functions and while just about everything that could go wrong, did go wrong, these were not some of them. The central administration of open-access tariff provisions under the ISO's OASIS probably helped bring resources quickly into the market.

- **Congestion Management** – Congestion management was not a problem in this crisis but the obvious limitations of certain transmission interfaces (*e.g.,* Path 15) became household words and there is now growing in-state political pressure to expand much need transmission capacity.

[7] For a detailed discussion of ELCON's position on RTOs, see Profiles in Electricity Issues: Regional Transmission Organizations (Electricity Consumers Resource Council, Washington, D.C., March 1999) at www.elcon.org.

- **Market Monitoring** – Fundamental market flaws were evident as soon as the California markets began operation in 1998. The ISO Board's Market Surveillance Committee repeatedly warned the Board (and FERC) of the potential for a crisis. Neither the stakeholder board nor FERC acted on these warnings.[8]

- **Interregional Coordination** – There is a long history of regional cooperation in the Western Interconnection that is generally absent in the Eastern Interconnection. For example, the Western Systems Power Pool (WSPP) experiment gave many control area operators experience with quasi-market interchange transactions. The Western Interconnection is also a single NERC regional reliability council. Hence, there is less Balkanization in western power markets, notwithstanding California's single-state ISO. During the crisis, the ISO faced fewer market barriers to the physically available resources. While this did not make up for the lack of adequate resources to meet demand during all contingencies, the case can be made that it substantially reduced the overall damages of the crisis.

What are the major lessons from the California crisis that bear most on RTO formation in general? First, and foremost, while the Cal ISO's original market design contributed to the crisis, the ISO's *operational control of transmission assets* helped manage the crisis over a huge regional market. This is a potential benefit that all RTOs can provide. The air traffic controller analogy is most relevant on this issue. During a severe weather contingency, somebody has to sort out the mess on a fair and nondiscriminatory basis. The crisis also exposed the failings of "ISO" structure vis-à-vis "RTO" structure. To its credit, FERC has addressed the needed changes. Removing transmission tariff administration, and the transmission reservation and scheduling process, out of utility control prevented "access" issues from making this crisis a true calamity. The absence in the West of the Balkanization that dominates the Eastern Interconnection (*e.g., eight* regional reliability councils) demonstrates the superior merits of multi-regional RTOs that ultimately replace regional reliability councils. Finally, the market flaws inherent in the California market's original design were known before the crisis materialized. This demonstrates that it is not sufficient to establish "market monitoring units" as FERC Order 2000 requires. There must be an audience for any warning, and that audience must be required to act.

RECOMMENDATIONS:

- **Minimize Number of RTOs** – A single, independent RTO should be established in each of the three interconnections. Each RTO should replace the incumbent NERC regional reliability council or councils. Independent

[8] See Market Surveillance Committee of the California Independent System Operator, "The Competitiveness of the California Energy and Ancillary Services Markets," March 9, 2000

transmission companies (transcos) should be subject to the operational control of an independent RTO.

- **Interregional Coordination** – Where multiple RTOs are allowed to coexist within an interconnection, it is critically important that each RTO's reliability and market interface practices are compatible with each other, particularly with regard to transactions across the boundaries ("seams") of adjacent RTOs. The integration of reliability practices involves procedures for coordination of reliability practices and sharing of reliability data among RTOs in an interconnection, including procedures that address parallel path flows, ancillary service standards, transmission loading relief procedures, and other reliability-related requirements in Order 2000. The integration of market interface practices involves developing some level of standardization of inter-RTO market standards and practices, including the coordination and sharing of data necessary of the calculation of TTC and ATC, transmission reservation and scheduling practices, congestion management, and other market coordination requirements in Order 2000.

- **Market Monitoring** – 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.