PSERC

Planning, Markets and Investment in the Electric Supply Industry

PSERC Executive Forum
March 7, 2008

Power Systems Engineering Research Center

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Planning, Markets and Investment in the Electric Supply Industry

PSERC Executive Forum
Held on March 7, 2008

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Power Systems Engineering Research Center

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This project was a collaborative effort by all of the participants in the forum held in New York City on March 7, 2008. Without their input and variety of perspectives, this synthesis would not have been possible. My modest aspiration is that this summary may be of some use to them, since that is its intention, as well as to the broader audience.

My thanks also go to the industry team members on this project: Jonathan Mayo and Rana Mukerji from the NYISO, Terry Boston from TVA and then PJM, Eugene Litvinov from ISO-NE, and Mark Sanford from GE. My particular appreciation is extended to my academic colleagues, Tim Mount and Ray Zimmerman at Cornell University, Fernando Alvarado from the University of Wisconsin-Madison, and Bob Thomas from Cornell University who is always providing sound advice, even if behind the scenes. My special gratitude is extended to Len Hyman (Black & Veatch), Tom Vitez (ITC Holdings), Jim Lyons (Novus Energy Partners), and Bob Hiney (NYISO Board member) who prepared stimulating presentations at the forum, and to Frank Wayno (Cornell University) and Dennis Ray, PSERC's executive director, who facilitated the discussion.

Finally, I note how many of those named above are "grey-hairs", either retired, or soon-to-be. They include Jonathan Mayo, Fernando Alvarado, Bob Thomas, Bob Hiney (from NYPA), and me. So, perhaps the greatest planning challenge facing this industry is the renewal of talented professionals. I know that PSERC is working hard on feeding that pipeline.

Richard E. Schuler, Executive Forum Coordinator

Executive Summary

On March 7, 2008, an executive forum conducted by PSERC, focused on the role and structure of the planning needed to elicit needed investment in the power system. The participants, some 23 senior electricity industry managers, were divided into five groups. Each group was composed of individuals from organizations deemed to have similar institutional, economic and geographic circumstances. Then, each group was charged with devising a preferred planning process for power system development.

While all groups agreed that planning was absolutely essential in this industry, differences emerged on virtually every other discussed aspects of planning, including:

- choice of the time horizon for planning (from 5-10 years to 10-20 years)
- whether planning should focus on incremental changes or should be used to evaluate fundamental system redesign (e.g., overlay of a higher voltage grid)
- who should pay for transmission expansion (e.g., only those who benefit from the expansion vs. everyone)
- what the scope of planning should be (e.g., electricity only vs. integrated energy resource planning)
- what the objectives should be (e.g., adding economic and environmental impact criteria).

Most of the differences in perspectives aligned with institutional, economic, and geographic environments in which the individual managers operated. If there are sound explanations of the historic differences in planning around the country, there may continue to be valid reasons for differing planning processes.

There was consensus on a number of planning issues. All participants agreed on the absolute necessity of conducting long-range planning for the electricity supply industry. To improve planning, participants recommended:

1. Better tools for demand forecasting, advanced electric system simulation, and planning
2. A mechanism and framework for multi-state regional planning and/or the coordination of separate plans across individual ISOs/RTOs and regions
3. Creation of an overarching entity to integrate broad social objectives (such environment and/or fuel diversity) within the more traditional reliability and economic considerations
4. Mechanisms to value the reduction in electricity use that encompasses the uncertainty in the availability of demand response resources as compared to the availability of "iron-in-the ground" supplies.

Finally, key points in presentations at the beginning of the forum included:

- the wide array of technological innovations that the industry may need to accommodate in its future planning
- the efficiencies to be obtained by a fundamental rescaling of transmission technology across a region such as through an extra high voltage overlay or "backbone"

- how proper locationally-differentiated markets provide the right incentives to build the right thing at the right place (incrementally)
- the need to align the incentives of the institutions and individuals who do the planning and make the investment decisions with the institutions and individuals experiencing the underlying risks and rewards of those decisions. In other words, people often spend other peoples' money very differently than they would their own money.

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Summary of the Executive Forum on Planning, Markets and Investment in the Electric Supply Industry

1. Issues

For over a century, comprehensive system planning has been essential for maintaining reliable electricity supplies because large amounts of the commodity cannot be stored economically. Electricity supply is the epitome of "just-in-time" manufacturing, where brownouts or blackouts will occur if adequate generation and transmission facilities are not in place and available to meet demand instantaneously. Given the long lead time required to plan, approve and construct new generation and transmission facilities (anywhere from three to over ten years), concerns about how that planning should be accomplished have increased substantially over the past decade because of today's restructured industry, particularly where institutions have been fragmented and de-centralized, and where market-based decisions are prevalent. What is certain is that the public has grown accustomed to highly reliable electricity supply, and any diminution of that service quality will not be tolerated. At the same time, public concerns have increased about the diversity and security of traditional fuel supplies that are used for generation, their environmental consequences and potential impact on climate change and about recent upsurges in the price of electricity.

Government responses include FERC Order 890 requiring regional economic planning in conjunction with previously mandated ISO/RTO reliability planning, and the requirement in many states for integrated energy resource planning to address public concerns about the broad social and environmental impacts of alternative energy supply scenarios, in addition to their effect on cost and reliability. Key questions are: about what, how, when and by whom should planning be done for electricity supply, particularly where many decisions are market-driven, and how should the process be designed to help, not impede, needed investment?

2. Format

A collaborative one-day forum with 23 senior electric power industry managers from across North America, together with five PSERC research faculty plus the convener and two facilitators, was held to explore how system planning might be organized most effectively under the different electricity supply circumstances and market structures that exist today. Four of the industry participants were invited to provide brief "food-for-thought" presentations, but the emphasis was on having groups of the participants develop their own "preferred" planning structures. Each participant was assigned to one of five groups that were arranged according to similarities in their regional, institutional, regulatory and power supply characteristics.

During the initial breakout session, each group was asked to characterize those key attributes of the environment in which they operated. Then they were charged with devising their preferred planning scenarios, describing what, when and by whom each type of planning might best be accomplished. The forum concluded with each of the five teams reporting their preferred planning scenario, followed by open comment and discussion among all forum participants. The intent was to identify similarities in preferred processes across all groups, and to understand the bases for differences in proposed planning procedures in terms of their varying institutional, market and regulatory structures.

3. Summary of Stage-Setting Presentations

All observations and opinions expressed by the following four presenters are theirs, personally, and do not necessarily reflect the views of the organizations with which they are affiliated.

3.1 Aligning Rewards to Risks and Responsibilities

Leonard Hyman, CFA, Senior Advisor to Black & Veatch, and former Senior V.P., Merrill-Lynch

In providing the business context for discussing preferred planning processes, Hyman emphasized the importance of aligning the incentives of the institutions and individuals who will be relied upon to bring a plan to fruition with their underlying risks and rewards. Focusing solely on legal or engineering principles is not sufficient. As an example, Hyman illustrated the mismatch that has existed under a fully regulated, vertically-integrated electricity supply system, where local utilities decide what's needed, and investors put up the money if they are confident regulators will make the customers pay them back. Here the customers are bearing all of the risk, ultimately, although they don't get to decide on initiating the investment. To emphasize the problem Hyman cited the difference in responding to risk when a party is investing someone else's money, as compared to their own - - a major source of the current financial problems arising from sub-prime mortgage financial instruments, as an example. But Hyman also emphasized that although the risk-reward structure for electricity supply may have changed in those regions where wholesale markets have been introduced, it is still misaligned, only in different ways.

As an example under both market-based and fully regulated supply, the same party, the load serving entity (LSE), is assigned the physical responsibility for maintaining reliable service. If supply is under a vertically integrated, fully regulated system (VIR), the LSE can actually do something about enhancing the physical reliability of the system: it can build the new facilities it thinks it needs. Under an unbundled market-based (UMB) system, the LSE must rely on market inducements to encourage other entities to provide the additional facilities. The difference in risk between these two cases arises from the certainty of timely physical construction. A market structure relies on a larger number of indirect inducements that are subject to strategic behavior by members of the supply chain and to disruption by third parties, like government as an example, who may cap price spikes during periods of scarcity and delay repayment to investors. Under both institutional frameworks, however, it's the retail consumer who ultimately pays the cost of the reliability they receive, but at present that cost is spread over a wide pattern of consumption, instead of being focused on the usage patterns that threaten reliability, and so under neither regime do customers get to choose the level of reliability they want - a further mismatch.

Hyman emphasized that in the markets for most services other than electricity that were formerly regulated, the end-use consumer pays for the cost of reliability and service quality, but those customers can choose from several providers, each of whom is responsible for providing a complete bundle of services as is the case of telecommunications Compare this situation with electricity supply. In the regulated, bundled world, customers may have borne the costs, but at least they could point a finger at some organization that had operating and financial responsibility for the reliability. In the unbundled world, the customer probably still foots the bill, one way or another, but no organization has the full operating and financial responsibility for the service delivered to the end-use customer. This diffusion of responsibility increases the risk to all members of the supply chain because suppliers may choose to do what benefits them rather than what produces the best product for the consumer. As an example, Toyota would not sell cars not knowing what its suppliers would charge or what quality product they would get from the supplier.

Finally, Hyman emphasized that when compared to other investment opportunities that are currently available to society, the building of needed electricity supply facilities should have easy access to adequate capital because of the essential nature of the commodity and its steady demand. The current impediment to capital access is a misaligned risk-reward structure for decision-makers and investors. Question: can effective planning change that?

3.2 Transmission Investment as the Key to Competitive Energy Markets and Renewable Resources

Thomas Vitez, Vice President of ITC Holdings Corp.

From the perspective of a transmission only firm, Vitez emphasized that transmission, although representing less than ten percent of the cost of electricity supply, is the backbone of that system. Not only is adequate transmission essential for supporting low-cost reliability of service by providing access to alternative facilities, that same physical functionality of low-cost access is a necessary prerequisite for any market to function competitively. And most public initiatives to develop renewable resources and/or assure a diversity of primary fuel supplies for security reasons, all rely on adequate transmission since the primary sources of energy are frequently concentrated, but at locations far away from each other, and in most cases, also distant from concentrations of customers who are in metropolitan areas.

Vitez identified three major impediments to getting the plans for new transmission facilities accepted by the public and the requisite regulatory authorities. (Note: since ITC is only in the transmission business and accepts FERC-approved rates as its sole economic regulation, they appear to have less concern than some other institutional forms about securing financing). The first barrier is a legal construct that has been used in many regulatory jurisdictions to determine the “need” for the new transmission facilities into two components: facilities to enhance reliability and facilities to enhance the economic benefits (reduce cost). Vitez emphasized, however, that most new transmission facilities satisfy both needs simultaneously and that any regulatory approval process that is based solely on only one of these benefits is likely to either greatly undervalue the net benefits of the proposed facility, or to have a less than optimal facility designed so it meets only the specified narrow measure of benefit.

The second barrier arises because of spatial boundaries that are drawn to define political jurisdictions and/or franchised utility service areas. In neither case would decisions about transmission expansion be made within these jurisdictions that are necessarily the best, economically, because the laws of physics and economics usually operate on a larger geographic scale than these man-made boundaries. Thus a new electric transmission line that easily passes the benefit cost test in aggregate may flounder if it crosses state lines (and/or utility jurisdictions) where one region stands to gain enormously, but the other might bear a slight loss. Economics teaches that where private businesses are the parties, surely a negotiated deal can be reached to let the line go forward, but when governmental bodies are involved, the deal-facilitating mechanisms are less obvious, particularly if the line is not popular in the high-cost region.

Vitez pointed to a third limitation that may compound some of the cases illustrated above: adequate tools frequently do not exist to accurately estimate the costs and benefits of new facilities and to identify who will receive or bear them, and when. Tools are needed to estimate accurately both the reliability and economic value of new facilities, and those net benefits must be projected over time by location to understand if and how the winners and losers may change over time. (Note: So far, transmission planning is done with linear transportation models that may not reflect accurately the binding voltage constraints that might arise over time in an AC system.) This requires major improvements in both demand and fuel forecasting models and in the network models used to simulate system behavior.

Finally, Vitez emphasized the additional challenge facing transmission planners in deciding whether or when to propose incremental versus transformational plans. An example would compare continuing to add additional 138kV lines to meet growing demand versus deciding that going forward the backbone system would be designed at 765kV. In most cases, leaping to a 765kV design could never meet the incremental benefit-cost test unless the planning horizon were over twenty years (typical line life is fifty years, at least), and reliance on such a forecast requires a high degree of confidence in the forecasting model. Nevertheless, a single 765kV line has the same capacity as thirty 138kV circuits, or five 345kV lines, so the land-use and cost consequence advantages of going with the higher voltage seem obvious if we knew where we're going to be with perfect foresight. Also, the separation between winners and losers will likely be even larger at these higher voltages, so the possibility of striking a political deal is daunting. A similar class of decision-making problems may arise in deciding to develop a new, remotely-located renewable resource like wind farms, since those sites may be distant from any existing transmission facilities, and the generation capacity may be developed incrementally; yet at the development's completion, a large 765kV circuit might have been the optimal transmission solution.

3.3 Clean Energy Technologies: The Effects of Planning and Markets on Technological Innovation, and vice versa

Dr. James Lyons, Chief Tech. Officer, Novus Energy Partners (formerly with GE Corporate R&D)

Dr. Lyons emphasized that many technological advances that have enhanced the commercial prospects for wind, solar and solid-waste-based electricity generation originated in Germany and Japan, largely as a result of their governments' strong R&D support and their policies and subsidies to encourage implementation. These technologies have now been adapted and adopted by many firms worldwide. Lyons summarized the state-of-the-art for each of these technologies, he assessed the current commercial viability of each and he projected the additional gains needed for each technology to become competitive without government subsidy. Lyons also identified any remaining institutional obstacles to the technology's successful deployment, in particular those that are due to the current design, operation and commercial practice of electric power systems in the U.S. He also described how some of these evolving technologies, if widely adopted, might transform the way in which the power system would be designed and operated in the future.

Lyons projected combined industry sales for these clean energy sources to be greater than a $200 billion within ten years. He estimated the compound annual growth rate of the amount of energy each source will provide to be: 25% for wind, 13-24% for biofuels (depending on whether 10% blends of ethanol continue to be promoted), 35% for hybrid electric vehicles and 40% for solar.

Wind Power markets are booming with standard land-based turbine unit sizes having doubled to the 2-3Mw range, and offshore units have grown to 5-6Mw each. When developed in farms, these state-of-the-art wind facilities are rapidly becoming more grid-friendly, providing real and reactive power control with variable ramp rates and the ability to ride through frequency and voltage transients. Improvements in wind forecasting and unit scheduling, together with increased market penetrations, has led to greater diversity among units and improved overall system performance when integrated with the rest of the grid. Still, the wind doesn't always blow where and when it's needed, so an expanded, regionally integrated transmission system and associated markets should be beneficial for the continued growth of wind resources.

Solar Photovoltaic generation is expected to parallel wind power's growth over the next twenty years, and by projecting annual reductions in cost that have averaged 4% per year historically, this source should become competitive with retail purchases of electricity from the grid before 2020. Market penetration today is limited in part by the availability of silicon feedstock for collection panels, but many other micro-scale technologies are emerging to compete. Much of the industry's projected expansion is thought to come through construction of "zero energy" homes, many of which would be developed in the sun-belt where solar capacity factors range between 20-25%. (ed. note: This market penetration may be slower in the near term because of the recent bursting of the housing bubble and slowdown in the economy). However, before widespread penetration can be realized, major revisions in the electric distribution system's design and operation may be needed to accommodate anticipated flow variations and net metering and to moderate voltage fluctuations that may result from the deployment of this technology. (ed. note: Innovations in storage and smart grid technologies that are discussed subsequently could be highly complementary.)

Waste Gasification at high temperatures (1500C) promises to utilize municipal solid, medical and hazardous wastes and to eliminate them in environmentally sound ways. Particularly when generated near large urban areas, this waste disposal method eliminates landfills and provides valuable feedstock for industry and/or it can be used to generate electricity cleanly. As an example, up to 25% of New York City's needs could be generated from this self-provided renewable source.

Electrified Transport, particularly in the form of plug-in hybrid electric vehicles (PHEV), has the potential to transform the nation's reliance on imported oil, and through that reinforcement, to have a major impact on the nature, pattern and quantity of electricity supplied. Today's popular hybrid electric vehicles are projected to be superceded by plug-in vehicles beginning in 2010 because their improved batteries should be capable of storing 20-40 miles worth of daily driving before requiring a re-charge. Since the median vehicle travels 33 miles per day in the U.S., this implies that half of the plug-in hybrid cars would be powered solely by electricity each day. Lyons also emphasized the large salutary effect on the environment that this conversion to electric-powered vehicles would have; the impediment is the relatively slow turnover in the vehicle fleet in the U.S. with less than ten percent of the stock being replaced each year.

Lyons stressed that the benefits of electric vehicles can be derived initially with little stress on the electricity supply system. As examples, if recharged at night, up to 50 percent of fleet could be converted to PHEVs without requiring additional generating capacity. And, the unit costs of providing electricity would be lower with less cycling of low-cost base load units and a greater utilization rate of nearly all generating capacity. There are security benefits as well since PHEVs reduce the consumption of foreign oil and shift dependence onto the electricity grid which relies on a diversified mix of primary energy sources that could grow even larger with greater reliance on solar and wind. But the variability of times during which these last two sources are available, coupled with the economic and environmental benefits of recharging batteries during off-peak periods, emphasizes an accelerated need for real time metering and the implementation of time of day pricing for nearly all customers if the potential benefits of PHEVs are to be fully realized.

These benefit-enhancing technological initiatives, therefore, would be greatly enhanced by the implementation of the Smart Grid with real time metering and widespread two-way communications protocols. This improved two-way information flow would allow both customers and generators to utilize their equipment more efficiently, enhance the prospects for distributed generation, and computer-controlled usage of power, particularly for thermal loads, and deploy storage capability most effectively. At the same time, the existing transmission and distribution infrastructure would be utilized more fully and efficiently. Dr. Lyons saw the needed overhaul of existing utility business practices and the need to mitigate possible expanded threats to the electricity system's security that might arise through information system incursions as the biggest challenges to the full implementation of the smart grid.

3.4 Putting It All Together in Theory and in Practice

Robert Hiney, Board Member & Interim President, NYISO (former Executive, V.P., New York Power Authority)

Bob Hiney emphasized that one aspect of electricity system planning has been decentralized in regions where wholesale markets have been implemented: determining how much generation to build where. In most markets, payments to generators are based upon locationally-differentiated-marginal-prices (LBMP), and because of the evolution of assembly-line-like combined cycle gas turbine projects and the widespread geographic availability of natural gas to fuel them, those choices can be left to individual suppliers. The only system planning required in these circumstances focuses on the adequacy of the transmission system, plus a check on whether sufficient new generation is being developed commercially to meet reliability criteria.

Of course it is important to have any plans for transmission expansion laid out and made public well in advance of anticipated generation investment so that developers can estimate how the evolving transmission network might affect LBMPs and therefore the most desirable location for constructing new generation. Any major transmission expansion that had not been previously discussed, that occurred only after a new generating plant had been completed and that has a substantial impact on locational price differences may well frustrate future private generation investment by increasing the perceived risk to developers greatly.

In contrast, the economical location of most other forms of generation like coal, nuclear, and large-scale hydro and wind projects is highly dependent upon the specific location of fuel and natural resources, and in the case of coal and nuclear, as examples, on being far away from population centers so that real and perceived environmental and human health and safety risks are minimized. Under these circumstances, the availability of adequate transmission must be planned in conjunction with the generation to be sure the new generators can get their energy to market. Hiney also acknowledged that a well-developed, uncongested transmission system can enhance the competitiveness of wholesale markets, and it may reduce the need for local capacity requirements. In some instances it can also improve the diversity of primary energy sources that are available, economically, at large demand centers, including enhancing the access to renewable sources, and so the expanded transmission network can provide added supply security. But a dense transmission network is expensive, and frequently the costs are not borne by specific beneficiaries but instead are "socialized" across all customers.

Hiney distinguished between the two historic roles for transmission: first, as a mechanism to provide bulk power service reliability at minimum cost through the ability to share a number of generators and parallel transportation paths in the event that any single facility is out of service. The second role is as a long distance transportation mechanism (a btu "pipe") to bring low cost power from remote locations to customers. This second role is an example where the optimal generation and transmission plan should be coupled to determine if it is more efficient to site the generator near its customers and transport the fuel (but possibly increase the potential adverse environmental effects of primary conversion, depending upon the energy source used to generate), or if it is better to build the plant remotely and haul the energy by wire,

If a market-based system is used to determine the expansion of generation, those decisions will be economically efficient only if the developer is forced to confront this locational trade-off, and that requires the generator to pay their fair share of any transmission system expansion that is required to maintain overall system reliability as a result of the location where the generating capacity is built. The generator should also be able to elect to pay the cost of having the transmission system strengthened or extended in order to reach more remote customers who may be willing to pay higher prices for their service. Under this "beneficiary-pays" principle, the new generator is seen to be the beneficiary in the first instance, and if some customers, as a result, receive lower cost service, the proper allocation of the enabling added cost of transmission will have been allocated to them through their supplier's price. The transmission expansions illustrated here are incremental, and so they fit nicely into the "beneficiary-pays" paradigm. Mr. Hiney outlined a possible transmission planning process for this instance that would begin by identifying any congested interface and would then enumerate the sequence of transmission investments that might be undertaken to increase transfer capacity across the congested interface while making optimum use of the existing transmission infrastructure and rights-of-way. Further, this "plan" would be updated periodically to reflect the effect of any demand changes and investments in new generation so that potential developers of new generation would be fully apprised of potential transmission alternatives, and their economic potential.

However, Mr. Hiney acknowledged that planning for and determining precise methods for cost allocation and recovery for large-scale system redesigns or upgrades covering wide areas, like those outlined by Mr. Vitez, would be more complicated. In most instances, he suggested that those costs might have to be socialized because the identification of beneficiaries might be so difficult ahead of time, but he also reflected that a socialized allocation frequently precipitates large political problems, and could lead to the siting of new gas fueled plants unnecessarily far from the population centers where that capacity is needed.

4. Description of Planning Groups

The forum participants were divided into five separate groups that were roughly arranged according to similar market/institutional/private vs. public experience. The reason for grouping executives with similar institutional experiences together was to minimize debates about which structure was preferred, and instead to focus upon preferred planning scenarios within each structure.

Each group began their discussion of preferred planning scenarios by characterizing the electricity supply environment in which they were operating in the following ways:

1. Primary Responsibility for Electric Grid Operation (e.g. ISO/RTO, integrated utility)
2. Primary Source of Dispatch "Cost" Information
    a. Markets (plus details on nature and type)
    b. Cost-Based (voluntary, regulatory)
3. Predominant Structure of Supplying Institutions
    a. G&T, T&D, completely unbundled, vertically integrated (VI)?
    b. Private, Private-Regulated, Public Power, Cooperative
4. Primary Responsibility for Resource Adequacy (for generation, transmission, distribution)
5. Siting Approval Process
6. Cost Allocation and Recovery
7. Geographic Span of Institutions (Intra-state, Statewide, Regional)

The self-identified group characteristics are summarized in Table 1.

Table 1: Summary of the Discussion Group's Background Characteristics and Business Environment

Group	Blue	Gold	Silver	Green	Red
Operator?	Independent.	Independent.	Indep./TRANSCO	Indep./Gov.	Indep./V.I Util.
Source of Dispatch Cost?	Mkt.	Mkt.	Mkt.	Mkt.	Mkt./Costs
Institutional Structural?	Gen/T&D	Gen./G&T	G&T/G&D/T	G&T	G&T
Adequacy?	Fed/State	Fed/State/TO	Fed/State/TO	State	V.I. Util.
Siting Approval?	State	State	State	?	V.I. Util.
Cost Allocation & Recovery?	Beneficiary/Postage Stamp	Postage Stamp	Beneficiary/License	?	Postage Stamp
Geographic Scope?	State/Regional	Regional	State	Regional	Regional

Major differences in the characteristics of electricity supply between the groups were:

1) Institutional structures:
   - Blue group had divested generation from T&D.
   - Silver had some transmission-only participants.
   - All other groups had predominantly integrated G&T.

2) Whether or not a public/regulatory agency in addition to FERC/NERC played a significant supply role at the bulk power level:
   - Green and Red groups had substantial government and/or vertically-integrated regulated utilities in the supply role.

3) Geographic scope:
   - Blue and Silver groups had some members with single-state jurisdictions/coverage.
   - Members of all other groups were regional entities.

All groups had some exposure to independent operators, and dispatch costs were determined by markets except for the Red group where some members received cost-based regulated prices.

5. Preferred Planning Processes by the Planning Groups

The dictionary definition of planning is: "A method for accomplishing something" (Webster). The three underlined words, starting with the last, emphasize that an objective (something) must be clearly identified, that the plan describes the path and/or means (method) for getting there, and that the emphasis is upon a successful outcome (accomplishing). In order to provide the participants in the forum with some common structure for their deliberations so that their scenarios might be compared, this definition was used to provide the template to aid them in the process of sketching out their preferred planning processes that are summarized in Table 2.

The Blue group emphasized the importance of relying on market signals to develop generation, demand response and merchant transmission facilities, but they also stressed that it is essential to have a regulatory/public-sector mechanism available as a fall-back for building these facilities if private investment were inadequate to ensure reliability. The need for two different plans, one short-run (reliability-based) and one long-run to include economic factors was emphasized, and the greatest problems that members of this group face are inter-regional coordination across ISOs/RTOs, and the lack of a coordinated government mandate to provide for broader social concerns like the environment.

While also relying on markets, the Gold group stressed the need for integrated planning at the RTO level to deal with all aspects of electricity supply since markets and planning are inter-related. The accountability for implementation can then be decentralized with different time horizons (e.g. generation to independent developers, and demand response can be delegated to LSEs or aggregators, but with no more than a 3-4 yr. horizon since its availability is more variable). Similar to Blue, Gold thought public agencies should set and be accountable for environmental and fuel diversity initiatives that have a long time horizon; however they thought many of those initiatives could be implemented through market mechanisms.

The Silver group's members focused on transmission planning, emphasizing that although RTOs can guide merchant transmission, all other transmission should receive regulated recovery with the costs socialized across all users. By comparison, they thought all generation planning and development should be market-driven. This group called particular attention to a need for demand-response and smart-grid-related standards on information flows, but then thought subsequent development should be market-driven. This group stressed technological innovation as one of their major objectives.

The Green group emphasized the need to conduct integrated system planning that involves all market participants and vendors, since currently no entity has the authority to oversee generation, transmission, distribution, demand response, the environment and fuel diversity. Furthermore, because of multi-state spillovers, a large regional geographic scope would help. But they emphasized that the essential prerequisite for any effective plan is a good load forecast; following that many iterative planning steps can be undertaken by the constituent sectors, each with different time-horizons, provided their individual plans and initiatives are reviewed in combination periodically. Implementation would be the responsibility of the party that gets paid.

The Red group's members focused on overall least-cost integrated resource planning, encompassing reliability, fuel diversity and community development as objectives. They saw themselves as being consumer-oriented and focusing on serving the consumers' long run interests as defined broadly (not just their electricity needs) through the provision of a bundle of options.

Table 2: Preferred Planning Processes

Characteristic	Blue Group	Gold Group	Silver Group	Green Group	Red Group
Objectives	No degraded system reliability Then let the market decide generation, demand response and merchant transmission	Reliable service through integrated plan for generation, transmission, distribution and environment Then let the market decide	Reliable service Reasonable prices Then let the market decide	Integrated system planning Reliable service Reasonable prices	Customer-oriented integrated least cost planning considering: • Cust. service • Reliability • Prices • Fuel diversity • Community development
Planning Responsibility (generation and transmission)	Markets first Regulatory back stop to build facilities if reliability threatened	Markets first	Markets for generation. RTOs guide merchant transmission. Regulation for T&D	Integrated system planning over large region involving market participants and vendors Implementation by compensated entity	By utility to serve customer needs through bundled service options
Incorporation of Demand Response (DR)	Value needs to be certain before inclusion	Use as short-run substitute for generation and transmission	Use DR and establish smart grid standards on info flows. Then let the market decide	No response	Customer service includes DR
Planning Time Horizon	Short-run plan: Focus on reliability Long-run plan: Include econ. and environmental factors	5 to 20 years	No response	Short-run (0 to 10 years): Focus on reliability Long-run (more than 10 years): Focus on economic factors	5 to 15 years. Construction planning more than 5 years. L.R. bi-lateral contracts for stability

Table 2: Preferred Planning Processes (continued)

Characteristic	Blue Group	Gold Group	Silver Group	Green Group	Red Group
Environment and Security Objectives	Government intervention required	Objectives should be set by government. Actions should be market-driven	No response	Authority for planning should not be governmental	No response
Planning Challenges	Achieving inter-regional coordination across ISOs/RTOs Absence of needed broad public interest mandates	Determining the value incorporating demand response in planning	How to motivate technology innovation and incorporate it in planning	Producing reliable demand forecasts Achieving multi-state coordination	Comparing bundled options in the long-run

6. Concluding Discussion among Forum Participants

What most participants seemed to agree upon during the brief time remaining in the forum was the need for some broad planning umbrella to guide the industry's evolution. Where they differed was on the nature, sequence and resulting obligations that result from the planning exercise. However, there seemed to be three further areas of general agreement among all participants:

1. A need for multi-state regional planning, or coordination of separate plans.
2. A need for some overarching entity to integrate broad social objectives like the environment and/or fuel diversity within the more traditional electricity reliability and economic considerations.
3. Analyses to value a "negawatt" because of the differing certainty of demand response as compared to "iron-in-the ground" supply responses to planning.

Finally, several participants called for an exhaustive cost-benefit analysis of various aspects and measures of electricity supply reliability to guide in setting and revising standards.

7. Observations of the Coordinator

What was so obvious from the enthusiastic participation by industry representatives at this forum was how deeply committed they all are to keeping the lights on at affordable prices. It's in the particulars of how to sustain and expand this level of service in a growing economy and evolving society that differences begin to emerge; we all see the future somewhat differently. But I believe that there are patterns to those differences in views that are rooted in past and present circumstances. And it is important to understand that those differences aren't merely due to accident or happenstance, but rather have evolved into fundamentally different electricity supply systems (institutionally, technically and philosophically) because each was a sound solution at the particular time, place and circumstances under which service was originally extended.

The different supply systems that exist today can be categorized roughly according to two geographic groups: one encompasses the contiguous northeast, middle-Atlantic and near mid-western states plus Texas and California (and some areas in-between those last two); the second group includes much of the southeast and all of the other states in the U.S. The first group typically has areas of very high population density, has or had a large industrial or extraction industry base, and has been served for some time by a fairly dense electricity supply network with multiple parallel paths, a variety of generation fuel supplies and in many places was operated as a "tight" power pool among the utilities before restructuring. Wholesale markets, with some degree of deregulation, have also been adopted and accepted for the allocation of supplies to users in most of these regions. The second group has larger rural spaces (with the exception of the burgeoning population centers of the past forty years in the south, plus Denver, Salt Lake City, Portland and Seattle) and has been served by a structure of lines that is more radial and at higher voltages (because of the distances spanned) than in the first group, with large government agencies directly involved in supply (in large part because full private sector supply was deemed unprofitable in these regions during the first half of the 20th century). It is not surprising then that different views about the efficacy of market allocation mechanisms, and therefore about the essential structure of the planning processes, might emerge between these two groups.

Yet all agree that planning must be done in order to get the transmission lines in place to haul the needed and lowest priced electricity from generator to buyers. And in areas where those decisions about building new generation is market-driven, knowing where those lines are to be built, their capacity and cost of transport, are prerequisites for having the private sector make sound investment decisions. What seems to differ in the views between the two groups is how forward-looking that planning needs to be and how large the leaps in technology should be that are planned for. Much of the planning in group one was incremental with commitments made only for projections of events within five to ten years, plus alternative futures scenarios presented for the ten to twenty year time horizon. Furthermore cost allocations and recovery mechanisms in these group one regions are based largely on the beneficiary-pays principle (except in Texas). By comparison, the planning in the other regions appears to commit to larger scale solutions, attempting to meet needs further into the future, with the transmission costs being socialized across all communities in their area. Looking back to today from fifty years from now we should be able to determine which approach was best − if both were allowed to develop on separate tracks. And the winner would be the region that was able to predict the future best, unless of course, different circumstances continue to persist in these two broad categories of regions. In that case, both approaches might be winners (or losers).

Here are the planning options: Having observed the inexorable growth in our appetite for electricity over the past 120 years, do we follow the trend and gamble on what now looks like the best solution for twenty years hence, or do we recognize the burgeoning evolution of both large- and small-scale renewable-resource-based technologies and take a “real-options” approach to planning so we can adopt each technology closer to the time when its worth is proved? This is a long-standing philosophical dispute. Do we seize on the “technological-fix” so we can rest in peace at night (only to wake up to the fact that we’re committed to a dinosaur), or do we wait and see which technology develops economically (only to discover that we must endure years of inordinate congestion while we build the facilities to utilize the latest marvel)? Is there a way to get the best of both worlds? Certainly developing and using better analytic planning tools would be a big help. Models of the complex electricity system are needed that are capable of estimating the detailed consequences of alternative futures. In addition to estimating the effects of alternative plans on the reliability and price of electricity supply, it would help if these models could estimate the interactive effects with other social initiatives like local environmental quality improvements, overall energy use and efficiency and sustainability in the use of resources. Question: with the proper electricity system plan, could substitutions between electricity for other fuels, like electricity for gasoline in the plug-in-hybrid vehicle, result in large reductions in the nation’s overall use of energy by using more (not less) electricity?

But meanwhile, until these advanced tools are developed we still need to plan, and that is helped greatly by improving the accuracy of forecasts about the future. While we can’t predict which technological innovations will become economical precisely when, frequently we can leave our system designs open to accommodate the most likely candidates, whether they be large central-station generators, renewable-based energy farms at remote locations or small decentralized solar, storage and geothermal devices distributed across the landscape at the buyers’ domain. And what all participants at the forum agreed would be beneficial for reducing the uncertainty about future events are the resolution of issues that we, as societies within the U.S., should be able to decide upon and control like: 1) environmental standards and how they are to be met, 2) some standards for exchange across ISOs/RTOs and 3) resolving the value of a “negawatt,” the reduction in demand by a watt such as through energy efficiency improvement or a demand response.

The economist-side of me has an easy solution for the last problem: have all retail suppliers charge their customers the true cost of supplying them electricity, minute-by-minute, including the capacity costs needed to maintain reliability, and provide that information to each customer so they can do something about it. Those customers, then, will readily reveal the value of consuming less by their actions. That should be an important consequence of “smartening-up” the grid, and it will provide planners with realistic data to forecast future trends in demand by time-of-day and projected price. Demand response will become routine and natural and not a cottage industry dependent upon regulatory constraint and subsidy. It’s time to stop treating electricity customers like children.

Establishing more-uniform, minimum environmental standards across the nation (e.g. for carbon) now seems to be under serious discussion: although many people in the industry, as well as most economists, would favor government-imposed effluent fees instead of the more politically popular cap-and-trade approach. The great benefit of effluent fees is that they can be set and projected with some consistency; whereas, the prices in permit auctions have been highly volatile, resulting in swings in electricity prices, threatening system reliability at times and therefore adding much greater uncertainty to the planning process. The only advantages of cap-and-trade within the U.S. is the opportunities it creates for financial speculators and the escape mechanism it provides for elected officials to avoid association with two politically dreaded acts: dividing up the added revenues in full public view and being labeled as a supporter of a "tax" increase. But if viewed properly as a "user-fee", not a tax, since we'd just be paying explicitly for the costs incurred by everyone as a result of carbon emissions, and if all revenues were ear-marked for deficit reduction in the short-run (and for an off-setting, pro-rata reduction in all federal tax revenues after the deficit was eliminated), those political inhibitions might be reduced.

An enormous remaining problem, however, is endemic to democracy: "deciding how to decide" on the siting of new facilities, particularly new transmission rights-of-way. Given the uncertainty and time delays those approval processes create, perhaps it's just best to plan around them. As an example, some jurisdictions are emphasizing having all transmission expansion take place on existing rights-of-way. Would it be simpler and less-costly in the long-run to just put some lines underground? But these last two solutions are far more viable in regions like group one where both existing customers and transmission line rights-of-way are denser. In most regions, depending upon government (which one?) to ram a solution down the public's throat is not likely to fly, unless we are willing to change our forms of government. And since the public's view on these issues varies widely across the nation, that may be the biggest reason why we will continue to have multiple electricity supply systems, different configurations and a variety of institutions around the country for some time to come. But that's no excuse for not deciding on the three items identified by this forum's participants: 1) establishing nation-wide minimal environmental standards including carbon emissions, 2) developing standards for exchanges across the borders of electricity control areas, and 3) valuing the "negawatt" and associated ways that reduce demand as required. Progress on those fronts should facilitate planning processes − and therefore investment in needed facilities.